February 17, 2026

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

**Re: Case No. U-21870 – In the matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief.**

Dear Ms. Felice:

Enclosed for electronic filing in the above-captioned case, please find **Consumers Energy Company's Exceptions to the Proposal for Decision**.

This is a paperless filing and is therefore being filed only in a PDF. Also included is a Proof of Service showing electronic service upon the persons included in Attachment 1.

Sincerely,

Digitally signed by Gary A. Gensch, Jr.
Date: 2026.02.17 14:41:26 -05'00'

Gary A. Gensch Jr.
Phone: 517-788-0698
Email: gary.genschjr@cmsenergy.com

cc: Parties per Attachment 1 to Proof of Service

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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**CONSUMERS ENERGY COMPANY'S EXCEPTIONS TO THE PROPOSAL FOR DECISION**

## I. INTRODUCTION

On January 29, 2026, Administrative Law Judge Jonathan F. Thoits ("ALJ") issued his Proposal for Decision ("PFD") in this case. On February 2, 2026, the ALJ issued the Appendices to the PFD, which provide the PFD's recommended revenue deficiency for the projected test year of $168.3 million (before removal of costs of the forestry ramp-up and the SAP S/4HANA project from the revenue requirement). The PFD's recommended revenue deficiency of $168.3 million is significantly less than both Consumers Energy Company's ("Consumers Energy" or the "Company") and the Michigan Public Service Commission ("MPSC" or the "Commission") Staff's ("Staff") positions on brief.[1] Consumers Energy submits that the rate relief recommended in the PFD, if adopted by the Commission in its entirety, would be below a just and reasonable level.

Most alarming is the PFD's recommendation on the return on equity ("ROE"), which represents a vast departure from the evidence presented and the reality in which the Company

[1] The Company's revised revenue deficiency request as set forth in brief is $422.8 million, and Staff's position in reply brief is $317.087 million. All positions provide for the recovery of an additional $24.3 million related to the distribution deferral.

operates. The ALJ's recommended 8.2% ROE is dramatically lower than the Company's proposed 10.25% and Staff's recommended 9.75%. The PFD's recommendation is also well below the Company's current MPSC-approved 9.9%. As will be detailed in these Exceptions, the ALJ's recommendation fails to correctly apply long-standing U.S. Supreme Court precedent and is not supported by either the law or the evidence. If adopted, the PFD's recommended ROE would be quickly and negatively received by the investment community, causing harm to the Company and its customers and jeopardizing the Company's access to capital at favorable rates or during times of unexpected shock to the capital markets going forward. It is crucial that the Commission approve a constructive revenue deficiency, ROE, and capital structure in this case that will enable the Company to complete the important work planned as proposed in the Company's filing.

In addition to the unlawful and grossly unreasonable ROE, many of the other recommendations in the PFD, if adopted by the Commission, would significantly impair achievement of the goal of improved electric reliability performance. Consumers Energy is aligned with the Commission's clearly stated mission of improving electric reliability for the residents of Michigan, and the Company's filing reflects the continued plan to implement the investments and operations needed to achieve that goal. The PFD is recommending reductions to distribution capital spending of more than $340 million. As detailed in these Exceptions, these reductions to proposed distribution funding are not supported by the evidence and will hinder the Company's ability to continue to improve reliability for customers. The Commission must provide the Company sufficient revenue to cover the investments and operations needed to achieve the desired improvements in reliability performance.

The Company has demonstrated its commitment to continued improvements in electric reliability, as well as in other areas of the business, and the record supports the Company's requests.

The size and scope of the PFD's recommendations are not justified. Consumers Energy urges the Commission to issue a decision in this case which provides the cost recovery needed to make the investments and conduct the operations necessary to improve reliability, as well as to perform the other important projects for the benefit of customers. The Commission should reject the PFD's proposed disallowances and grant the Company the cost recovery necessary to deliver the performance its customers deserve.

## II. RATE BASE

### A. Net Utility Plant

#### 1. Distribution Capital Expenditures

##### a. High Voltage Distribution

###### (i.) HVD Lines Reliability

In the High Voltage Distribution ("HVD") Lines Reliability sub-program, the Company identifies lines that consistently exhibit poor reliability performance and determines the most efficient, cost-effective remediation strategy to reduce risk and prevent future outages. 3 TR 1189. As part of this sub-program, Consumers Energy evaluates asset health and risks related to conductor, insulators, and poles; and addresses those identified risks through line rebuilds, pole top rehabilitations, and switch and pole replacements. 3 TR 1191. Exhibits A-109 (MLH-3) and A-110 (MLH-4) detail the planned projects. The HVD Lines Reliability subprogram also includes line sensors which identify abnormal line conditions, allowing the Company to investigate and address issues before a failure occurs. 3 TR 1206. Right-of-Way ("ROW") acquisition for reliability projects is also included in this sub-program. 3 TR 1207. The Company projects capital expenditures of $133.667 million in the bridge period and $107.667 million in the test year for the HVD Lines Reliability sub-program. 3 TR 1207.

The record establishes multiple benefits associated with the HVD Lines Reliability sub-program, and the Commission has previously approved increased spending in Case No. U-21585. The Company's projected spending aligns with previously approved levels. The continuation of this investment into the test year is reasonable and should be approved.

The PFD recommended reductions to this sub-program, adopting the Attorney General's proposal to spread pole replacement costs over five years. PFD, page 49. Specifically, the PFD recommended a disallowance of $6.304 million in the bridge period and $5.002 million in the test year for HVD pole replacement. *Id*. This recommendation should be rejected. The Company's position in this case is in line with the findings from the Liberty Consulting Group ("Liberty") audit report. The poles set for replacement have been red tagged because they have reached an unacceptable state of deterioration. 3 TR 1358. While the Company previously tried to integrate pole replacements into larger projects to consolidate work, this practice has left a significant backlog. These poles are deteriorated and present a risk to both safety and reliability if they fail. 3 TR 1358. Allowing these poles to remain on the system longer increases the risk of failure; thus, the PFD's recommendation should be rejected.

**(ii.) HVD Substation Reliability**

The HVD Substation Reliability subprogram ensures the continued safe and reliable operation of substations by addressing asset health risks and replacing deteriorating equipment. 3 TR 1214. 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 System Average Interruption Duration Index ("SAIDI") impacts. This sub-program includes fixing and fortifying circuit breakers, transformer bushings, and switches that

are in poor health. The Company also performs other targeted replacements for specific equipment such as voltage transformers and substation lightning arresters. 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. Overall, investments in this sub-program are needed to address asset health issues in HVD substations. 3 TR 1218. These investments let the Company prevent future potential high-impact outages that would result in significant customer interruptions and loss of system resiliency. 3 TR 1220. During the pendency of this proceeding, the Company modified its projected capital expenditures for this sub-program to $22.230 million in the bridge period and $39.680 million in the test year. See Exhibit A-115 (MPK-5); Exhibit A-219 (MPK-29).

The PFD failed to recognize the Company's reduction of expenditures in rebuttal and recommended disallowances in the amount of $34,820,000 in the bridge period and $28,718,000 in the test year for the HVD Substations Reliability subprogram. PFD, page 56. This recommendation is inappropriate as it recommends a bridge year disallowance that is greater than what the Company is requesting. This recommendation is based on adopting the reductions proposed by the Attorney General, who also failed to acknowledge the Company's expenditure modification.

The PFD generally supported the opinion of the Association of Businesses Advocating Tariff Equity ("ABATE") that although some reliability investments are needed for the HVD system, overall capital and operating and maintenance ("O&M") investments should be focused on the Low Voltage Distribution ("LVD") system. PFD, page 56. This contention fails to recognize the importance of investing in the HVD system. This fact was supported by the Commission when it authorized a meaningful increase in HVD reliability on March 21, 2025 in

Case No. U-21585. The record shows that there are a number of benefits associated with the HVD Substation Reliability sub-program (3 TR 1214-1226), and the Company must invest in the HVD system to ensure that the backbone remains resilient, able to quickly restore customers if outages occur, and to minimize the occurrence of outages in the first place. 3 TR 1165.

The PFD's recommendation is based on the claim that the Company failed to provide sufficient support for the spending increases for circuit breakers and switches and Other replacements. PFD, pages 55-56. This is incorrect. The ALJ's argument ignores the Company's Reliability Roadmap, which included a thorough review of HVD substation asset health, concluded that the Company needed to increase investment in replacing various substation components, including circuit breakers. 3 TR 1359. See Exhibit A-129, pages 119-129. Figure 109 in Exhibit A-129 (MPK-19) lays out the increased investment needed to replace various substation components, including circuit breakers. Additionally, the Company explained the issues it has had with circuit breakers, noting that many of them are now severely obsolete, are in poor asset health, and replacement parts are scarce. 3 TR 1221-1222. The Company's projected expenditure levels are a step to correcting this issue. As for the increased number of projects being undertaken in the Other/Miscellaneous category, the Company supported the specifics for this spending category. Exhibit AG-13 shows the increased work being undertaken in the spending category. These levels are being driven by the review of asset health discussed in the Reliability Roadmap. Exhibit A-129 (MPK-19). Accordingly, the PFD's proposed spending reductions should be rejected.

**(iii.) Transformer Bank Replacements and Substation Rebuilds**

The Transformer Bank Replacements and Substation Rebuilds sub-program is focused on the capital repair or replacement of HVD and Strategic Electric Customer ("SEC") substation

equipment, primarily large substation transformers ranging from 2 MVA to 100 MVA, and the rebuilds of entire substations. 3 TR 1227. These projects are typically large and occur over multiple years, with costs incurred across several years before completion. 3 TR 1228. The replacement of large substation transformers and the rebuilding of HVD and SEC substations is necessary when the asset health of a substation or a large transformer deteriorates. This reduces the risk of failures that could impact customer reliability. 3 TR 1228. Proactive replacement of these assets prevents long-duration outages, which can last 18-24 hours, as the replacement often requires the use of an emergency mobile substation. *Id*. Many substation assets have outlived their intended lifespan, and while maintenance and inspection have extended their performance, rebuilds and replacements are needed to address high risk assets. The Reliability Roadmap indicates the need to replace an average of 12 transformers yearly between HVD and strategic customer substations to address poor asset health. 3 TR 1230. In this case, work is planned for 14 transformers in the bridge period and three in the test year, with progress payments made to ensure future availability of transformers. 3 TR 1231. The Company is projecting Transformer Bank Replacements and Substation Rebuilds capital expenditures of $46,666,000 in the bridge period, and $37,667,000 in the test year. 3 TR 1234.

The PFD adopted Staff's recommendation to reduce the Company's capital expenditures for this sub-program. This would reduce the Transformer Bank Replacements and Substation Rebuilds capital expenditures by $20,396,000 for 2025, $6,240,000 for the four months ending April 30, 2026, and $22,250,000 for the 12 months ending April 30, 2027. See 6 TR 4419. While the PFD recognized that Staff's linear spending assumption may not be completely appropriate in all cases (PFD, page 62), it adopted the use of this methodology despite the fact that many HVD capital sub-programs do <u>not</u> have consistent month-by-month spending levels, making it

inappropriate for future spending levels to be projected linearly based on a short-term amount of data. 3 TR 1343. HVD projects, particularly substations, require temporary system reconfigurations to deenergize certain components while not interrupting any customers. Because of this, many types of HVD projects can only be undertaken during certain parts of the year. *Id*. This can be due to weather, electric load conditions, or other limitations that impact when system reconfigurations are needed before the work can be undertaken. *Id*. Furthermore, many HVD projects are large and complex and therefore may not have closely similar spending levels every month. This is why the use of a linear spending assumption to review projected costs is unreasonable.

The PFD incorrectly claimed, when adopting Staff's methodology, that "the Company failed to adequately justify its projected expenditures to support its claim that it will catch up from its slow start in 2025, nor did it demonstrate that additional issues, like the permitting or planned outages problems that Consumers claims limited project execution earlier, will not occur going forward." PFD, page 63. This conclusion reflects a misunderstanding of the Company's testimony. The Company explained that in 2025, the Company faced limitations over the summer into the early fall that impacted its ability to take needed planned outages. 3 TR 1346. Additionally, many of the projects in this sub-program are very large and come with permitting requirements, and the Company faced permitting delays earlier this year. 3 TR 1346. Company witness Megan L. Hayward stated that "[f]or example, the Buskirk Creek rebuild project (see Exhibit A-109 (MLH-3), page 3, line 9) was delayed in receiving a necessary permit from the Department of Environment, Great Lakes, and Energy ("EGLE") earlier in 2025, causing an approximately two-month shift in the project schedule and causing over $4 million in investment to be shifted from 2025 to 2026." 3 TR 1346. This testimony explained why the Company's

spending was shifted during the year, why the year-to-date spending through June was lower than projected, which is why the use of Staff's linear spending assumption is inappropriate.

Despite the delay, the Company evaluated its projected spending for the Transformer Bank Replacements and Substation Rebuilds and continues to forecast that it will catch up and achieve the full projected bridge period amount. To accommodate for the weather and system load conditions, the Company will schedule a greater portion of planned work in the earlier part of the year preceding the warmer months, as well as ramping up work again when it is cooler later in the year. 3 TR 1346. This would shift the work to be undertaken so that it is accomplished in the earlier and later part of the year. Therefore, the PFD's recommended disallowance should not be adopted for the bridge period or test year.

**(iv.) Metro Rehabilitation**

The Metro system provides underground electric service in six key downtown areas: Battle Creek, Flint, Grand Rapids, Jackson, Kalamazoo, and Saginaw. 3 TR 1182. Initially installed between the 1910s and 1950s, the infrastructure was designed to manage the density of downtown city centers and facilitate electrical repairs. *Id*. The Metro System faces asset health risks like other parts of the distribution system, necessitating investments to ensure continued reliability. 3 TR 1183. However, it does not face as many asset health challenges as other parts of the system, and investment in Metro Reliability is remaining relatively flat. *Id*.

The Metro Rehabilitation sub-program focuses on mitigating risks from deterioration by inspecting and upgrading the civil and electrical components of the Metro assets. It addresses assets at high risk of imminent failure to maintain public, employee, and contractor safety, as well as system reliability. 3 TR 1265. The sub-program includes two main investment categories: crushed duct replacements and vault or manhole rehabilitation. *Id*. Crushed duct replacements

involve replacing deteriorated duct banks with new concrete-encased duct banks and running new cables through them. 3 TR 1265. Vault or manhole rehabilitation involves replacing damaged or deteriorated structures to eliminate safety hazards. *Id*. The expenditures for the Metro Rehabilitation sub-program are aligned with the Reliability Roadmap, which addresses asset health concerns. The Company is requesting approval for expenditures to improve overall reliability and address components most vulnerable to failure. Projected capital expenditures for the Metro Rehabilitation sub-program are $7,987,000 for the bridge period and $5,993,000 for the test year. 3 TR 1267; Exhibit A-113 (MPK-3).

The PFD recommended a reduction to the bridge year expenditures in the amount of $4,152,000 and a test year reduction of $3,041,000. PFD, page 67. In adopting the Staff's recommendation, the PFD questioned the Company's explanation as to why the use of linear spending assumption is inappropriate. See PFD, page 66. Although the Company explained that it tends to shift projects to the later part of the year due to frost since these projects involve crushed concrete-encased duct bank replacement and manhole rehabilitation (3 TR 1347), the PFD questioned this fact indicating that frost would also be an impediment to project execution in November and December. PFD, page 66. This however fails to recognize that while it might get cold and snow in November, it takes quite a while for the ground to freeze/frost. Typically, five or more consecutive days of subfreezing temperatures are necessary to have the ground freeze, which is what makes digging difficult. Moreover, while the PFD pointed out that the Metro Rehabilitation subprogram was higher in February and in March, then it was in any of the months from May through August of 2025 (PFD, page 66), this was not due to projects undertaken in these months and simply due to carryover costs from projects that occurred the previous fall. This highlights the Company's point that the spending in this program is not linear, and it is

unreasonable to assume that this sub program would have consistent month-by-month spending as suggested in the PFD. Therefore, the PRD's recommended disallowance should not be adopted for the bridge period or test year.

**(v.) System Control Projects**

The System Control Projects sub-program aims to enhance the management of the distribution system by improving operations of control centers, streamlining operations, and enhancing remote control capabilities to improve safety and reliability. 3 TR 1294. This subprogram includes operating technology enhancements and operations center modifications. *Id*. Operating technology enhancements focus on improving the functionality and operations of the System Control Center, Distribution Control Center, and Work Management Centers, which are responsible for monitoring the system and ensuring a reliable power supply for all customers. *Id*. Operations center modifications involve additional equipment and infrastructure to improve the Emergency Operations Center, which are identified during after-action reviews for each event. The benefits of the System Control Projects sub-program include improved monitoring and control capabilities, which streamline operations and reduce the impact of any single fault, thereby reducing interruptions for customers. 3 TR 1295. The Company projected a test year investment of $279,000 for this sub-program, maintaining the investment levels approved by the Commission in a previous case.

The Commission should reject the PFD's recommended bridge year reduction of $184,000 and a test year reduction of $74,000 related to the System Control Projects sub-program. PFD, page 70. The Company's projections, especially for 2026 and 2027, are reasonable reflections of likely spending amounts. The history of this sub-program, as shown in Exhibit A-95 (MPK-3), line 44, shows that spending has been somewhat variable from year to year. 3 TR 1348. In fact,

the Company's actual spending in 2024 was $896,000, which demonstrates that the Company has and can spend the projected amounts. *Id*. Despite this fact, the PFD contended that "the Company needs to provide more information on its spending plans – particularly in the case where a project is discretionary and where it does not appear to be on track with its projected spending." PFD, pages 70-71. But no party to this case contended that the Company did not provide enough information on spending for this sub-program. Additionally, the PFD stated, without explanation or support, that the spending for this sub-program is discretionary, but this ignores the fact that Staff also agrees that "the investments in the System Control Projects will benefit customers and better enable employees to provide safe and reliable electricity." 6 TR 4421. More importantly, while the PFD indicated that the Company does not appear on track with its projected spending (PFD, page 71), there is no evidence in this case that supports the contention that the Company spends at consistent levels in this sub-program throughout the year. In fact, the record indicates that spending has been somewhat variable from year to year. 3 TR 1348. The Company can spend at projected levels and a partial snapshot of spending in time does not demonstrate that it can and will not do so. The PFD's recommended disallowance should be rejected.

**(vi.) <u>LVD Substations Demand Failures</u>**

The LVD Substations Demand Failures sub-program is designed to support the capital repair or replacement of failed LVD substation equipment to restore customer service and maintain the reliability of electrical service. 3 TR 1318. This sub-program is planned and executed when an event occurs and is divided into four investment categories: regulators, reclosers, transformers, and other equipment. *Id*. The average failure rates from 2020 to 2024 indicate approximately four LVD substation transformer failures, 43 recloser failures, and 64 regulator failures per year, which are used to project future investment needs. *Id*.

Related to this sub-program, Consumers Energy projects bridge period capital expenditures in the amount of $11,923,000, and test year expenditures in the amount of $8,961,000. 3 TR 1319; Exhibit A-113 (MPK-3). The Company's projected test year amount provides the necessary investment to support capital repair or replacement of failed equipment, addressing interruptions and maintaining service quality. Without investment in this category, customers would remain without electric service or experience unacceptable service quality when substation equipment fails. 3 TR 1319.

At pages 72-73, the PFD adopted Staff's recommendation to reduce test year costs by $580,000 and bridge year costs by $580,000. This reduction is based on the use of Staff's transformer cost. This unit cost amount is incorrect. To start, Staff indicated that it calculated a five-year average unit cost of $700,000 based on the data presented in Exhibit A-130 (MPK-20), page 2, line 30. 6 TR 4423. However, the average cost is actually higher than this. Exhibit A-130 (MPK-20), page 2, line 30, shows that the Company spent $13,357,103 over five years on 18 transformers in this sub-program, which yields an average of $742,061. At a minimum, this should be the transformer unit cost used in the five-year average calculation.

The Company, however, maintains that the correct transformer unit cost is $845,000. Transformer unit costs are still generally increasing. 3 TR 1349. Company witness Hayward testified that "[d]uring the latter part of 2024, the Company made purchase orders based on competitive bids for transformers, with 33 similar sized transformers costing an average of $812,000, indicating a recent increase." *Id*. These recent purchases and associated costs support the Company's proposed transformer unit cost, and the PFD's recommendation should be rejected.

### (vii.) LVD Substations Rehabilitation

The LVD Substations Rehabilitation sub-program is designed to address capital repair or replacement of LVD substation equipment that is at imminent risk of failure, rectify code violations, and replace obsolete equipment. 3 TR 1247. Obsolete equipment includes reclosers, breakers, fuses, regulators, lightning arresters, and switches that are no longer available from manufacturers, have depleting inventory, and for which replacement parts cannot be purchased. 3 TR 1248. The program aims to reduce outages and improve reliability by addressing these issues. As shown in Exhibit A-113, Consumers Energy is projecting LVD Substations Rehabilitation capital expenditures of $40,895,000 in the bridge period, and $31,147,000 in the test year.

The PFD adopted the Attorney General's recommended disallowances of $14,689,000 in the bridge period and $8,082,000 in the test year for transformer replacements. PFD, page 82. This adjustment was related to the replacement of Allis Chalmers transformers. Allis Chalmers substation transformers need to be replaced due to a design deficiency that makes them vulnerable to certain faults, leading to potential failures. 3 TR 1250. As of 2025, the Company has 31 original Allis Chalmers units and six rewound units in service that are considered at risk of developing the condition. 3 TR 1251. While the PFD recognized that these faulty units will all need to be replaced eventually, it argued that a slower approach to transformer replacement is reasonable in light of the size of the Company's rate case. PFD, page 82. As a general matter, the size of the Company's rate case is unrelated to the reasonableness of the costs associated with replacing known faulty transformers. The PFD never explained why it would be reasonable to further delay replacing these transformers. Allis Chalmers transformers have a long-documented history of issues, and the Company's approach in the instant case is based on resolving this ongoing matter. 3 TR 1351.

The Company based its bridge period projections on the Commission's approved spending levels from Case No. U-21585. The Company has been making investments in line with what the Commission previously found to be reasonable and prudent. Any reductions to this previously approved spending would be improper. Thus, the Company's projected spending levels should be approved.

**(viii.) LVD Substations Capacity**

The LVD Substations Capacity sub-program is essential for maintaining the reliability and safe operation of the Company's electric distribution LVD substations, which are critical for local reliability as they often serve single communities. 3 TR 1288. This sub-program addresses asset health risks to prevent outages and is driven by the need to manage localized load growth, impacting the capacity requirements of LVD substations. Investments are necessary to ensure these substations can handle increased demand and maintain service reliability, supporting economic development, and meeting the growing electricity demands of communities. This sub-program involves capital expenditures for installing new substations or substation equipment and upgrading existing ones to ensure customer electric loads are served within the operating capacity of the installed equipment. 3 TR 1288. Starting in 2024, HVD line work and ROW procurement associated with LVD Substation Capacity projects are included to improve investment categorization and project cost tracking. *Id*. Projected capital expenditures for the bridge period are $29,656,000, and for the test year, $22,251,000. 3 TR 1291; Exhibit A-113 (MPK-3).

On page 86, the PFD recommended a disallowance of $16,420,000 for the bridge period and $11,074,000 for the projected test year from the Company's forecasted capital expenditures for the LVD Substations Capacity subprogram. This adjustment was based on the contention that "the Company's justification for these projects in the bridge and test periods is sorely lacking."

PFD, page 86. This characterization is belied by the record evidence. The Company explained that the LVD Substations Capacity investments are necessary for the overall operation and reliability of the electric distribution system by preventing future overloads and addressing existing overloads, which would eventually result in equipment failure and customer outages, while ensuring the Company has adequate capacity on the distribution system to serve customer load. These projects are identified based on identified capacity needs and work to mitigate planning criteria violations. 3 TR 1353. The number of projects undertaken is dependent on pockets of local load growth and can vary from year to year. *Id*. In addition to providing the projects, the location, and the type of investment; the Company also provided the number of customers benefitting from each project in this sub-program in the bridge period and test year, which are identified in the Benefit Type and Benefit columns of Exhibit A-109 (MLH-3), page 10, and in Exhibit A-110 (MLH-4), page 10. While the PFD wanted additional information on load growth and the condition of the current substations in these areas, the information that the PFD believed to be necessary was never requested. See Exhibit AG-72, page 4. The Company based its project costs on the specific work scope for each project and historical costs from similar projects. Moreover, the Company has been making bridge period investments for several months in line with what the Commission found reasonable and prudent in Case No. U-21585. 3 TR 1354. This level of work and the associated spending are adequate to meet the sub-program objective to serve customer electric loads within the operating capacity of the installed substation equipment, thereby ensuring the long-term and reliable operation of the electric distribution LVD substations, and the PFD's recommendation should be rejected.

### (ix.) HVD Strategic Customers New Business

The HVD Strategic Customers New Business category consists of the capital costs to meet the new business needs of large C&I customers that are too energy intensive to be served by the LVD system. 3 TR 1296. This category of the New Business Program includes both existing customers and 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. *Id*. This subprogram (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. 3 TR 1304-1305. The Company projects $90.045 million in the bridge period and $43.860 million in the test year for HVD Strategic Customers New Business. 3 TR 1298.

The PFD agreed with the Attorney General and ABATE that certain costs related to canceled projects and unspecified "high probability" projects should be disallowed in both the bridge and test periods. PFD, page 92-93. Based on this finding, the ALJ recommended that $4.340 million and $22.965 million for two canceled projects, as well as $7.349 million for unspecified projects should be removed from the bridge period. For the test year, this PFD found that $20,619,000 for the project that was listed as canceled, and the additional $6.470 million in high probability projects, should also be disallowed.

While the Company agrees to the removal of $20,619,000 in the test year related to a dedicated customer substation that has been cancelled, it disagrees with the remainder of the PFD's recommendation. This includes the removal of costs in the bridge year related to cancelled

projects. Although it would normally be reasonable to remove money allocated for cancelled projects, the HVD Strategic Customers New Business sub-program is unique in that the Company entered into contracts with customers to perform these projects, and executed work based on those agreements with customers. 3 TR 1361. The Commission has routinely determined that having a signed contract with the customer results in the associated investments being reasonable and prudent to be included in rates. 3 TR 1366. While the PFD alleged that this fact is unsupported, there are a number of Commission proceedings where it was indicated that a contract was necessary for the inclusion of projected costs in a case. See, e.g., MPSC Case No. U-21806, September 30, 2025 Order, pages 15-16 ("U-21806 Order"). If a project is cancelled because of customer action (or inaction), the investments undertaken by the Company were still reasonable and prudent at the time they were made. In this sub-program, actual costs already incurred for these projects should not be disallowed. 3 TR 1361. Additionally, the Company is actively seeking recovery from the customer related to expenses incurred and will refund any amounts received back to customers. *Id*. In the meantime, it would be unreasonable to prohibit the Company from recovering these reasonably incurred costs.

The PFD, at page 93, further maintained that recovery of these costs is unreasonable since "the Commission did not review the Company's contracts (one of which is now breached, apparently) with any customer to assess whether the terms and conditions of those contracts were reasonable, prudent, and sufficiently protective of the Company and other ratepayers in the event the project did not go forward." But the Commission does not typically review and approve customer contracts. Nor has the Commission indicated that it would want to review all of the Company's contracts with customers. The PFD unreasonably set a new approval standard, without

support, and then criticized the Company for not following that standard. The ALJ's purported method for determining whether the Company's costs are reasonable is inappropriate.

High probability projects are projects that are in active contract negotiation that are highly likely to move forward in the near future, such that the Company must invest in the bridge period and test year to ensure that customer needs can be met. 3 TR 1299. For these high probability projects, Company witness Hayward explained that "the customer either has accepted a commitment offer letter from the [Michigan Economic Development Corporation] and/or has identified a specific site in the Company's service territory for location." 3 TR 1300. These projects have long lead times in terms of ordering materials and other logistical considerations, and prospective large customers need the certainty that they can connect to the Company's system on their schedule. *Id*. The PFD proposed removal of bridge and test period costs related to unknown "High Probability" projects under this sub-program. PFD, page 94. This is contrary to the Commission's direction in Case No. U-21585, where the Commission ruled that it was reasonable and prudent for the Company to strategically procure critical inventory designed to make it easier to execute on high-probability projects in this sub-program when they arise. 3 TR 1361. See March 21, 2025 Order in Case No. U-21585 ("U-21585 Order"), pages 41-42. These expenditures at issue in this case are in line with that decision. Additionally, the Company shared in discovery, that since the time of filing this case two high probability projects have signed contracts. 3 TR 1363. These contracts were shared with the parties in this case during discovery as seen in Exhibit AG-15, page 4. The costs associated with this sub-program are reasonable and prudent, and the PFD's recommendation should be rejected.

### b. Low Voltage Distribution

#### (i.) LVD Asset Relocations

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. 3 TR 1914. Make-ready work is typically requested by a communications company to place new attachments or modify existing attachments on Company poles. 3 TR 1918. 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*.

The PFD recommended approval of Staff's proposed reduction of $12.435 million in the 12--month bridge period, $4.086 million in the 4-month bridge period, and $13.495 million in the test year using the Case No. U-21585 unit cost of $7,686 adjusted for inflation. PFD, page 115. The Commission should reject the proposed reduction because it does not represent a reasonable projection of the anticipated unit cost.

The Company's projected and historical costs in the Make-Ready investment category reflect the Company's cost net of the recovery amount from attaching third parties. 3 TR 2042. But when evaluating unit costs for Make-Ready work, the full cost of the work should be considered. The Company is not projecting any increase in the full unit cost of the work compared with the actual unit cost in 2024. Make-Ready work total unit cost was $22,556 in 2022, $22,657 in 2023, $24,131 in 2024, and is projected to remain at $24,131 in 2025 through 2027. 3 TR 2043, Table 1. While the net unit cost in 2023 was $7,869, compared with $12,453 in 2024, that net unit cost was unusually low only because of the unusually high recovery from third parties in 2023. *Id*. Staff's projected net unit cost of $7,686, adopted by the PFD, assumes a higher recovery from

third parties than is expected based on the Company's historical experience. The Commission should approve the Company's projected Make-Ready expenditures which include a reasonable expectation of the recovery amount from attaching third parties.

### (ii.) LVD Reliability

#### (a.) LVD Lines Reliability

The LVD Lines Reliability sub-program includes projects to ensure the long-term safe and reliable operation of the Company's LVD lines. 3 TR 1928. 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. 3 TR 1928. 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. 3 TR 1929. 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*.

The PFD recommended approval of Staff's proposed bridge period spending reduction in Zonal Health investments of $14.76 million consistent with 2024 spending. PFD, page 125. Staff's proposed reduction was based on Staff's contention that it is not evident that the Company considers other approaches to improve reliability outside of Zonal Health Improvement projects. 6 TR 4372-4373. The Commission should not adopt this recommended reduction because the evidence makes clear that the Company does consider different approaches before proceeding with Zonal Health Improvement projects. The RAE is a tool that the Company uses to identify zones with recent reliability challenges and the most opportunity for improvement. Once those zones are identified, the Company develops and prioritizes projects to address reliability in those zones.

3 TR 2040. The Company then uses a least-cost-best-fit approach to identify the most cost-effective way to improve reliability, comparing a variety of potential solutions with one another before pursuing a particular Zonal Health Improvement project. *Id*.

The Company provided an example of this project selection process in the concept approval at Exhibit A-226 (JMP-6). In this example, using zonal analysis the Company identified a zone in the bottom 3%, and considered three different alternatives to address the problem. The Company selected the median-cost alternative that would result in the highest customer benefit. See Exhibit A-226 (JMP-6). This illustrates the Company's process of considering multiple approaches to solve an identified reliability concern and selecting the least cost option that would resolve the issue. 3 TR 2040. The Commission should approve the Company's projected Zonal Health Improvement funding to allow the Company to complete the planned reliability projects selected pursuant to this deliberate and thorough process.

The PFD also recommended that the Commission approve Staff's recommendation for additional detail in the future regarding impacts of Zonal Health Improvements. PFD, page 125. This additional detail is not necessary because the Company has been performing this type of work since 2013, and has presented data showing the clear benefits from these projects. 3 TR 2041. For example, the Company provided examples of recent Zonal Health Improvement projects and their benefits. See 3 TR 1939-1940. The Company also measured the performance of circuit improvement projects by comparing the three years of outage history of the zone prior to investment to the outage history for the one to three years after investment, and Zonal Health Improvement work has produced on average a 53% reduction in outages. 3 TR 1938. Accordingly, the Company has demonstrated the benefit to reliability of these projects and the Commission should approve the proposed funding to continue to improve reliability.

ROW projects secure necessary land or land rights for LVD projects. 3 TR 1943. The PFD recommended approval of the Attorney General's proposed test year reduction of $11.465 million based on the assertion that the Company did not adequately support its ROW projection. PFD, page 138. The Commission should reject this reduction because the Company reasonably projected ROW expenditures based on a percentage of Targeted Circuit Improvement spending.

ROW spending is projected to increase because of the overall increase in LVD Lines Reliability work. 3 TR 2044. Since 2020, ROW costs have averaged 14% of Targeted Circuit Improvement spending, with a range from 11% to 19%. 3 TR 2043. In the test year, the Company is projecting ROW spending at 12% of Targeted Circuit Improvement costs, which is less than the recent 14% average. *Id*. The extent to which these costs apply to particular projects is typically not known until closer to project completion because they involve items such as creation of easement documents and any new easements and payments for these easements. 3 TR 2044. The Company's methodology of projecting ROW expenditures based on a historical spending percentage is reasonable and should be approved.

**(b.) <u>LVD Repetitive Outages</u>**

The LVD Repetitive Outages sub-program addresses areas of the distribution system that consistently experience recurring customer interruptions, measured by Customers Experiencing Multiple Interruptions ("CEMI") inclusive of Major Event Days ("MEDs"). Thus, this sub-program targets specific zones for improvements to address issues of frequent interruptions. 3 TR 1961. Under the Commission's Service Quality and Reliability Standards that went into effect on April 10, 2023, no more than 6% of customers should have four or more outages in a calendar year (CEMI-4+). 3 TR 1961. The Company is planning to increase investment in Repetitive Outages to achieve this 6% standard. 3 TR 1962.

The PFD recommended approval of Staff's proposed 20% reduction to bridge period and test year projections, totaling approximately $10 million, based on the Company's previous spending in this area. PFD, pages 149-150. The Commission should reject this proposed reduction in the work needed to reduce repetitive outages and meet Commission requirements. As demonstrated in Exhibit A-219 (MPK-29), line 5, the Company is ramping up spending in Repetitive Outages. These proactive investments will replace deteriorated assets and reduce customer exposure to outages, as well as improve employee and public safety and reduce the overall costs associated with the emergent response to additional interruptions. 3 TR 1964. The Commission should approve the full funding needed to complete the planned work to reduce these repetitive outages.

The PFD also recommended that the Commission "direct the Company to robustly document and account for its expenditures in this subprogram in its next rate case – to include a correlation of the avoided customer interruption minutes with actual reductions from historical outage minutes." PFD, page 149. The Commission should reject this recommendation because the Company already provided information relevant to the Repetitive Outages Program. In the U-21585 Order, page 73, the Commission stated that it expected the Company to demonstrate that Repetitive Outages expenditures "were indeed spent on addressing reliability in LVD repetitive outages." In response to this expectation, the Company provided Exhibit A-169 (JMP-4), which identifies the repetitive outages that had substantive investment in 2023 and 2024, and states how many outages occurred both before and after the work was completed. 3 TR 1967. The PFD's recommendation that the Company also provide "a correlation of the avoided customer interruption minutes with actual reductions from historical outage minutes" is not only unclear, but also does not recognize the purpose of Repetitive Outage expenditures. The purpose of

Repetitive Outage expenditures is to address recurring customer interruptions, and Exhibit A-169 (JMP-4) demonstrates how those recurring outages were addressed by identifying the number of outages before and after the work.

**(c.) Resiliency**

Overhead to underground ("OHUG") conversions, or undergrounding, will replace certain sections of overhead LVD lines with underground lines and associated equipment to avoid outages caused by falling trees. 3 TR 1985. In Case No. U-21389, the Company proposed an undergrounding pilot, comparing the benefits and costs of this work. The Commission approved this proposal to cover approximately 10 miles of undergrounding. 3 TR 1432. The Company proposed to expand on the undergrounding pilot with an additional 25 miles in Case No. U-21585, but the Commission did not approve this proposal because the results of the original pilot were not yet available. *Id*. At the time of the filing of the instant case, the Company had completed 8.8 miles of undergrounding at an average cost of $422,000 per line mile installed. 3 TR 1433. In Case No. U-21389, undergrounding was projected to cost $400,000 per line. Much of the reason for the actual average cost of $422,000 was from a single outlier 0.6-mile project that cost $902,000 per line mile. 3 TR 1433. Without this project, the average cost for the pilot was approximately $398,000 per line mile installed. *Id*. As a result of this pilot, the Company has learned to prioritize undergrounding work where construction is simplified by minimizing the use of boring as the primary undergrounding technique, avoiding the need to underground large amounts of secondary, and avoiding customers who have a large number of unmarked private utilities. 3 TR 1436.

Applying these lessons learned to allow the Company to develop a more economical program at scale, the expected Present Value of the Revenue Requirement ("PVRR") for undergrounding projects at scale using the Utility Cost Test ("UCT") is $5.1 million compared

with a $5.0 million PVRR for both alternatives of Aerial Spacer Cable or Tree Wire. 3 TR 1437. And when using the Societal Cost Test ("SCT"), which is a methodology that evaluates utility programs and their impact on society as a whole, undergrounding is a better value to customers than the alternatives. 3 TR 1438. Since the PVRR for undergrounding and the alternatives are similar, and undergrounding is expected to improve reliability by 90% or more, the Company is proposing 50 miles of undergrounding in the test year at a projected cost of $20 million. See 3 TR 1439, 1988. The Company plans to scale the program to 400 miles per year by 2028.

The PFD recommended approval of the Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan's (collectively "MNSC") proposed $15.48 million reduction in test year OHUG conversions based on MNSC's arguments that most outage minutes avoided are in a small number of miles and that there is a need for individual Benefit Cost Analyses ("BCAs") for each undergrounding project. PFD, page 182. Acceptance of MNSC's proposal would mean completing only 11.3 of the Company's proposed 50 miles in the test year. See PFD, pages 180-181. While it is true that some of the OHUG conversion projects are expected to avoid more customer outage minutes than other projects, the fact remains that each of the Company's planned undergrounding projects will provide avoided customer outage minutes. See Exhibit A-167 (JMP-2), page 21. And as discussed, the BCA that the Company completed for the OHUG conversion shows that undergrounding costs are comparable to the alternatives while providing at least a 90% reliability improvement. 3 TR 1587. The Commission should approve the Company's requested funding for these undergrounding projects to allow the Company to move forward with improving reliability for all of the customers associated with the planned projects.

The PFD also recommended approval of the Ecology Center, the Environmental Law & Policy Center ("ELPC"), Union of Concerned Scientists ("UCS"), and Vote Solar (Collectively referred to as "CEO") proposal that the Company provide additional information related to the Vulnerable Communities Resiliency Plan ("VCRP") beginning the earlier of the Company's next rate case or Distribution System Plan ("DSP"). PFD, pages 182-183. While the Company did not disagree with CEO witness Lee Shaver's proposals for assessing the impacts of the VCRP, it is important to note that the first year of VCRP investments will not be complete until the spring of 2027, and there will likely be some lag after that time until the Company has sufficient data to begin to draw conclusions. 3 TR 1608.

**(iii.) Metering and Transformers**

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. 3 TR 2022. Projected capital expenditures are $227.963 million in the bridge period and $207.782 million in the test year. 3 TR 2023. 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. 3 TR 2024. In 2025 and beyond, the Company expects overhead transformer purchases to remain generally level, but padmount transformer purchases to significantly increase because of increased undergrounding work for new service connections and primary and secondary circuits and the need to support customers adopting electric vehicles ("EVs"). 3 TR 2024.

The PFD recommended approval of the Attorney General's proposed reduction in LVD transformers of $15.305 million in the bridge period and $14.782 million in the test year. PFD, page 199. The PFD stated that the Company's increase in transformer expenditures was not

sufficiently supported. *Id*. The Commission should reject this recommended reduction because the increase in LVD Transformer spending is driven primarily by the growth of purchases in 1-phase and 3-phase padmount transformers needed for undergrounding, new business activity, and projected EV adoption. 3 TR 2062. The Attorney General's proposed reduction, adopted by the PFD, was based on applying the 2023 to 2024 growth rate for padmount transformer purchases. 3 TR 2248-2250. But expansion of undergrounding drives the need for padmount transformers above the already increased need reflected in the increase from 2023 to 2024. 3 TR 2057. Accordingly, the Commission should reject the PFD's recommended reduction to ensure that the Company has sufficient padmount transformers to meet customer needs.

**(a.) Metro Modernization**

The PFD recommended approval of the Attorney General's proposed removal of all projected costs for the Metro Modernization project in the amount of $305,000 in the bridge period and $650,000 in the test year. PFD, page 213. The PFD stated that the Company did not adequately support the costs for the project, and that future requests for recovery of expenditures for this project should include costs for full project deployment and a BCA. *Id*. The Commission should reject the removal of these projected expenditures because the Company demonstrated that the Metro Modernization project will improve reliability through remote operations and will improve safety for the public and the Company's electric line workers. 3 TR 1746.

Safety incidents in underground Metro electrical systems can be extremely dangerous when they occur. 3 TR 1746. The project includes the use of specialized sensors designed to detect water or gas hazards within the Metro system, assessment of switching equipment enhancements to improve reliability and efficiency, development and integration of a communications package to facilitate exchange of data, and investigation of remote-controlled capabilities to streamline

Metro operations. 3 TR 1692. These monitoring and switching capabilities that are being introduced into Metro vaults will reduce operational costs through remote operations and easier maintenance of switching equipment. *Id*. They will allow the Company to address issues before they lead to catastrophic failures, avoiding equipment failure outages. 3 TR 1694. The project also speeds up operations and outage restoration, providing for shorter customer outages. 3 TR 1692-1693. Many of the Metro systems serve Environmental Justice ("EJ") communities, and as such the project will reduce the length of outages to those vulnerable communities, as well as to other priority and commercial customers. 3 TR 1693.

The Company included an analysis indicating the avoided customer minutes interrupted expected from the project. 3 TR 1693; Exhibit A-151 (SAM-10). The project also meaningfully avoids 185 work hours of exposure for electric line workers in dangerous confined spaces. 3 TR 1693. This sensing and switching technology that the Company will deploy as part of the Metro Modernization project is not new to the utility industry – the technology is only new to the Company. 3 TR 1746. Like many of the projects within Grid Automation, the Metro Modernization project will allow the Company to engineer this proven technology for use on the Company's system to benefit the safety and reliability of customers. *Id*. Accordingly, the Commission should approve the funding to implement this sensing and switching technology on the Metro system in order to benefit reliability and improve safety.

**(iv.) <u>Electric Distribution Asset Management</u>**

Electric Distribution Asset Management ("DistAM") applies asset management principles and processes to electric distribution assets to maximize their value over the life of the assets, resulting in improved reliability through reduced equipment failure. 3 TR 1701. DistAM will collect distribution asset data into a single centralized database that will provide enhanced

integration into asset health performance. 3 TR 1701-1702. DistAM will support the creation of asset health scores, which will aid the Company in addressing equipment issues before outages occur. 3 TR 1702. This work is consistent with industry best practices defined in ISO 55000(1) and the Michigan Infrastructure Council Asset Management Program. 3 TR 1702.

DistAM investment categories include Asset Repository ("AR"), Asset Performance Management ("APM"), and Asset Investment Planning ("AIP") – the AIP category is now complete. 3 TR 1702. Projected expenditures are $1.740 million in the bridge period and $4.050 million in the test year. 3 TR 1703. As of March 31, 2025, the Company had invested $7.9 million in the DistAM program as follows: (i) $5.8 million for the AIP which was launched in 2024; and (ii) $2.1 million for the AR. *Id*.

The AR will provide a single, centralized database to store essential distribution asset data, and can identify relationships among various equipment components so that they can be risk-assessed together. 3 TR 1704-1705. This will create efficiencies by allowing for the bundling of work at the same locations. 3 TR 1705. The centralized AR also improves work efficiency by avoiding the need to access various software to pull and analyze data. 3 TR 1706. The tool will also support the ability to complete advanced risk analytics and create asset health scores. *Id*. The benefits of the AIP and APM will not be fully realized without an AR feeding consistent, comprehensive data. *Id*. The Company is projecting AR capital expenditures of $970,000 in the bridge period and $1.410 million in the test year. 3 TR 1703.

The APM is a software tool that takes the base of asset data made available from the AR to develop a health index or health score for assets across electric distribution. 3 TR 1708. The tool will use advanced algorithms to develop health and risk monitoring through a standard and common interface for Company employees to generate, monitor, and make decisions for

identifying opportunities to address assets requiring attention based on asset health and risk. *Id*. This ability to monitor asset health and risk will improve reliability and availability of physical assets, minimize risk of asset failure and operating costs, provide or enhance condition monitoring, enable predictive maintenance, and provide for health and risk models. 3 TR 1708-1709. The Company is projecting APM capital expenditures of $770,000 in the bridge period and $2.640 million in the test year. 3 TR 1710.

The Commission originally approved the DistAM project in Case No. U-20697 and again in Case No. U-20963. The concept approval at the time of the Commission's original approval estimated $12 million for the project. In the U-21585 Order, the Commission stated that approval of increased DistAM costs would require updated data. *Id*. The Company provided updated data and total costs in this case. The Company's total projected expenditures for the DistAM program through the test year in this case is $13.6 million, which is $1.6 million more than the originally projected $12 million. 3 TR 1743. Costs have increased from the original projection because the Company discovered the need for the expansion of additional Information Technology ("IT") applications and learned that the quality of the Company's data would not meet the requirements of a vendor provided solution for APM. 3 TR 1704. The BCA at Exhibit A-152 (SAM-11) shows the total projected costs for the project are less than the total benefits, with a positive net present value ("NPV") of $1.482 million. Exhibit A-152 (SAM-11), page 1.

The PFD recommended approval of the Attorney General's proposed reductions in DistAM expenditures in the amount of $1.74 million in the bridge period and $4.050 million in the test year. PFD, page 222. The PFD stated that the Company has not shown that the Company's expenditures are reasonable and will provide adequate value. *Id*. The Commission should reject this denial of all DistAM funding in the bridge period and test year.

Continued funding of the DistAM program is important because the three primary components of the DistAM – the AR, APM, and AIP – all build on each other to improve efficiency. 3 TR 1743. While the project costs are expected to increase since the initial concept approval, the Company continues to refine these costs, including avoiding $3.3 million in capital and $1 million in O&M expense based on building an internal APM solution instead of a vendor provided solution. This avoided $1 million per year in O&M expense was not included in the BCA at Exhibit A-152 (SAM-11), further supporting the economics of the project. 3 TR 1743.

DistAM will optimize how the electric distribution system is proactively maintained and managed, enabling the Company to develop and manage asset health on the system to optimize asset performance, control costs, and allow the Company to provide a more comprehensive overview of its system in future distribution plans. 3 TR 1711. The Liberty audit of the Company's distribution system supports the completion of the DistAM project, stating that the Company's "proposal for creation of DistAM comports with our recommendations about enhancing asset management" and that the "system appears designed to support a programmatic, analytically founded, and data driven asset management strategy, all of which are in keeping with our recommendation." 3 TR 1711-1712. And as ordered in the Commission's July 10, 2025 Order in Case No. U-20147, the Company will be required to provide a data-based review on the general health and condition of its distribution system assets in the DSP. 3 TR 1745. This is the type of data that the APM and the overall DistAM project will enable the Company to deliver. The Commission should approve the costs associated with this program.

### 2. Generation Capital Expenditures

#### a. Updated Capital Projections for Generation Capital Projects

During discovery in this case, Staff asked the Company to provide any updates to its estimates of its bridge period and test year capital expenditures for fossil and hydroelectric plants, including Ludington Pumped Storage, that have occurred since the Company's direct testimony was filed. 6 TR 4466. The Company provided the requested updates as shown in Staff Exhibit S-8.0. Based on those updates, Staff witness Laura Maio recommended that the Commission adjust the bridge period capital expenditures included in rates for this case as shown in Staff Exhibit S-8.1. 6 TR 4466. Company witness Richard T. Blumenstock agreed that Ms. Maio's updated cost estimates reflected in Exhibit S-8.1 are appropriate and should be used to set rates in this case. 6 TR 3607. The effect of these updates results in a reduction in the Company's bridge period capital investments of $5.453 million. See 6 TR 3607.

However, the Company noted that Ms. Maio's adjustment failed to reflect all of the updates shown in Exhibit S-8.0. 6 TR 3607. The update provided by the Company in discovery included $6.920 million of capital spending in the bridge period for (i) the D.E. Karn Unit 4 Transformer Fire Capital, (ii) the Covert Main Steam Tee Header Replacements, and (iii) the Covert Unit 3 Main Steam Tee Header Replacements. 6 TR 3607. The Company had actual capital spending on those projects of $3.238 million through June 2025. 6 TR 3607. The Company submits that the Commission should include the $6.920 million amount in the total capital approved in the case as well, which would further adjust Staff's adjustment to an increase of $1.467 million for the bridge period in this case, rather than a $5.453 million reduction.

The ALJ declined to recognize the costs for those three projects included in the updated estimates or to offset Staff's downward adjustment. The ALJ reasoned that the Commission has

previously found that it is generally inappropriate for the Company to attempt to introduce new projects in discovery or rebuttal because it would deprive interested parties of the proper notice and opportunity to permit satisfactory review of the projects. PFD, page 233. Consumers Energy does not dispute that the Commission has generally taken that policy position in previous cases. The Company also generally accepts the Commission's logic for that policy. However, there is a distinguishing feature to these particular proposals that makes the issue different in this case. Over the last few electric rate cases, Staff has adopted a routine practice of asking for these kinds of post-filing updates for all generation capital projects over $1 million through discovery and then proposing an adjustment to reflect the Company's updates. See MPSC Case Nos. U-21389 and U-21585. In Case Nos. U-21389 and U-21585, Staff recommended adjustments that reflected the net amount of both the increases and the decreases in the Company's updated estimates since the filing of direct testimony. In Case No. U-21389, the net effect was a decrease of about $10.3 million for the bridge period and test year.[2] In Case No. U-21585, the net effect was an increase of about $3.2 million for the bridge period and test year. U-21585 Order, pages 125-126, 128. Consumers Energy accepted Staff's proposed adjustment in both cases because it fairly and even-handedly reflected the changes in the Company's capital plan regardless of the direction of the adjustment.

However, in this case for the first time, Staff recommended an adjustment that reflected all of the cost reductions from the Company's updated estimates but selectively disregarded the three projects discussed above that involved cost increases in the Company's updated estimates.[3]

[2] The Commission did not explicitly call out this adjustment in its March 1, 2024 Order in Case No. U-21389; however, the adjustment was incorporated into the Commission's final revenue requirement.

[3] Consumers Energy acknowledges that Staff *did* include the cost increases for most of the projects based on the Company's updated forecasts in Exhibit S-8.1, which the Company appreciates – just not the increases associated with these specific projects.

Compare Exhibits S-8.0 (listing the Company's updates) and S-8.1 (listing Staff's adjustments based on the Company's updates). This situation is different than previous cases in which the Commission rejected late-added projects for consideration in rebuttal testimony because, in this case, (i) Staff solicited the update through discovery early in the case, (ii) Staff reviewed the updates sufficiently to determine that nearly all of them warranted inclusion in rates, (iii) Staff offered no explanation or reason of any kind why only these three projects were excluded or indicating that there was any basis to find the projects unreasonable or imprudent, and (iv) the Company has significant actual costs incurred for the projects. In *Michigan Consol Gas Co v Michigan Pub Serv Comm*, 389 Mich 624, 640; 209 NW2d 210 (1973), the Michigan Supreme Court found that the Commission acted arbitrarily and unreasonably "by refusing to consider increases in costs in the future while taking into account future reductions . . . ." The Supreme Court quoted approvingly from the lower court's holding in that case that, "[c]ertainly at first blush it would appear to anyone steeped in 'due process' considerations that it is grossly unfair to include certain items of decreased cost in rate determination while at the same time to exclude items of increased cost." *Id*. at 633. This principle applies here as well.

Unlike previous cases where the utility, of its own initiative, sought to add new projects for consideration in rebuttal, Staff actively sought out updated information early in the case so that it would have sufficient time to review the material. Therefore, the Commission's concern expressed in previous cases about such late additions depriving interested parties of the proper notice and opportunity to permit satisfactory review of the projects is inapplicable to this situation. It would be manifestly unjust and inconsistent with the Michigan Supreme Court's precedent to allow Staff to selectively incorporate all updates reducing costs while ignoring some of the updates gathered at the same time showing increasing costs unless Staff or another party could articulate

some reason why those increases are not reasonable or prudent. That did not occur in this case. If the Commission will not accept all of the reasonable cost increases included in the update, then it should not accept any of the cost decreases included in that same update. Either way, Staff's proposed disallowance of more than $5 million and the ALJ's recommendation to accept that adjustment is unwarranted and should be rejected.

**b. Class Cost Estimates for Generation Capital Projects**

The ALJ recommended that the Commission adopt Staff's proposed adjustment to the Company's generation capital estimates for projects over $1 million in this case to reflect the low end of the Company's Cost Estimating Manual's "expected accuracy range." PFD, page 241. The ALJ primarily relies on the Commission's prior decisions on this issue in reaching his recommendation. Consumers Energy continues to urge the Commission to reconsider this issue, since it is almost certain to lead to under-recoveries due to the statistically improbable nature of all its estimates being at the lowest accuracy level rather than converging to the center. Nevertheless, given the Commission's prior decisions, these Exceptions will only focus on the ALJ's rejection of an alternative proposed by the Company.

In this case, Mr. Blumenstock explained that the Company accounts for the uncertainty of less mature estimates by including contingency in its cost estimates. 6 TR 3613. Based upon prior Commission orders which have consistently disallowed the recovery of contingency in projected capital expenditures, the Company has not included them in its request for investment recovery. 6 TR 3613. As such, Mr. Blumenstock explained that the Company's projected capital expenditure amounts already reflect a 5% reduction to the project cost based upon the removal of contingency. 6 TR 3613. That means that the 5% contingency amount is being removed twice with the use of the low end of the accuracy range. 6 TR 3613. At the very least, the recommended disallowance

levels should be reduced by the 5% contingency amount that has already been removed from the projected capital expenditures. 6 TR 3613.

The ALJ's only response to that alternative request was to argue that the Commission "has repeatedly found, while allowing for contingency may be appropriate in project planning, the inclusion of these uncertain costs in customer rates is unjust and unreasonable." PFD, page 240, quoting MPSC Case No. U-20940, December 9, 2021 Order, pages 9-10. On that basis, the ALJ recommended against "reintroducing a 5% contingency to offset Staff's proposed reduction." PFD, page 240. The Company does not dispute that the Commission has determined that contingency should not be included in rating rates, and the Company is not even asking the Commission to reconsider that issue in this case. Contrary to the ALJ's characterization, there is no proposal to "reintroduce" contingency. However, contingency is that portion of the estimate that was meant to account for the uncertainty of estimates at earlier stages of engineering development. If the Commission removes the contingency from the Company's estimate first, and then treats the remaining estimate value as if it still contains all of the uncertainty from the class's "expected accuracy range" and reduces it all the way to the low end of the range again, it is necessarily double-counting the contingency. That is unfair. The original estimate included a 5% contingency that was removed. Any reduction based on the "expected accuracy range" of the class cost estimate should be applied only to the original estimate for each project, which would have the effect of removing all contingency plus any additional amount of uncertainty indicated by the accuracy range above the level of the contingency. Even if the Commission is unwilling to reconsider the class cost estimate adjustment as a whole, it should, at the very least, avoid the double-counting that is currently occurring. The Commission should reverse the ALJ and require

the class cost estimate adjustment to be reduced to account for the 5% contingency already removed from the total project estimates before inclusion in this rate case.

**c. Covert Unit 3 LTSA Extras**

The PFD recommended that the Commission reject the majority of the disallowance proposed by ABATE for the Company's Long-Term-Service-Agreement – Extra Work not Included in the Contract ("LTSA Extras") work at the Covert Plant. PFD, pages 260-261. The PFD found that, unlike earlier rate cases, the Company now has – and presented – historical data to support the reasonableness of most of the costs for the bridge period and test year of this case. PFD, pages 260-261. That determination was heavily based on the fact that (i) the inspections for Covert Unit 2 were now complete, (ii) the inspections identified specific LTSA Extras work that needed to be complete, (iii) the Company had incurred actual costs for LTSA Extras work on Unit 2 that exceeded the original estimate for the work, and (iii) the other units are essentially identical and have similar operating history and pre-defined work scopes to Unit 2. PFD, pages 259-260. However, the PFD did recommend a $400,000 disallowance because the forecasted cost for LTSA Extras work on Unit 3 in the test year was higher than the actual costs incurred for Unit 2 in 2025. PFD, pages 260-261. The PFD referred to this difference as "inexplicable, as it appears wholly speculative . . . in comparison to the Company's testimony regarding the actual spending in relation to Unit 2." PFD, page 261.

The ALJ's confusion is easy to clear up. The ALJ correctly recognized that the inspections for Unit 2 identified specific LTSA Extras work that needed to be completed and that the actual cost to complete that work in 2025 was approximately $12.7 million. However, the Company did not complete all of the work identified by the Unit 2 inspection during 2025. In addition to the $12.7 million of work completed in 2025, there was about $400,000 worth of work that the Company was not able to complete in 2025, but is completing early in 2026. Therefore, the

forecasted LTSA Extras cost for Unit 3 is not $400,000 higher than the cost for Unit 2 – it's the same amount because it includes the additional work that is still underway for Unit 2. The Company forecasts that there will be less work needed for Unit 1, which is why that cost forecast is lower. But, Units 2 and 3 need the same scope of work and are expected to cost the same. Therefore, the Commission should decline the $400,000 disallowance recommended by the ALJ because there is not a cost discrepancy between the Unit 2 actual costs and the Unit 3 projected costs.

**d. <u>Jackson Plant LTSA Extras</u>**

The PFD recommended that the Commission generally approve the Company's forecasted LTSA Extras work for the Jackson Plant as it has in past cases. PFD, pages 264-265. However, the ALJ recommended that the Commission hold the forecasted amount at the level originally included in the Company's direct testimony in this case ($2.115 million) rather than adopting the $3.472 million updated forecast that Staff proposed and the Company agreed to. PFD, page 265. The ALJ reasoned that the increased amount "is coming at a late stage of the case, potentially depriving intervenors of an opportunity to reasonably object to the increased amount." PFD, page 265. However, this recommendation should be rejected for the same reasons discussed above regarding all of the post-filing capital spending updates requested by Staff for generation projects over $1 million. There is even more reason to reject this disallowance because, in this instance, Staff recommended *including* the cost increase in final rates. Not only did Staff obviously have the *opportunity* to review this cost increase, the Commission can infer that Staff *acted on that opportunity* because Staff affirmatively recommended approval. Again, consistent with the Michigan Supreme Court's holding in *Michigan Consol Gas*, it would be arbitrary, unreasonable, and unfair – to the detriment of the Company's due process rights – to include all future cost

reductions in rates while selectively excluding expected cost increases. The Commission should decline to adopt the ALJ's $315,000 reduction in Jackson LTSA Extras investments.

#### e. Preservation of Evidentiary Appeal

On page 278 of the PFD, the ALJ responded to the Company's statement preserving its right to appeal the evidentiary ruling issued by the ALJ on November 7, 2025 in this case. In the PFD, the ALJ observed that Consumers Energy had not filed an appeal and stated that "it is unclear why Consumers wishes to preserve the stricken testimony for 'later briefing.'" Rule 433 of the Rules of Practice and Procedure Before the Michigan Public Service Commission provides procedures for appealing an ALJ's ruling made during the course of a proceeding to the Commission. Mich Admin Code, R 792.10433. Rule 433 generally permits a party wishing to appeal an ALJ's ruling to file an application for leave to appeal within 14 days of the ruling, but Rule 433(5) also states, in relevant part, that "[a] party's failure to file an application for leave to appeal does not constitute a waiver of the right to challenge any ruling of the presiding officer either in a brief or in exceptions to a proposal for decision." Consumers Energy's statement preserving its right to appeal the ALJ's evidentiary ruling was included in its Initial Brief to communicate the Company's intent to appeal the issue as part of these Exceptions as permitted by Rule 433(5) and to avoid any later claims that the Company waived its right to appeal. Consumers Energy does not believe it was necessary for the ALJ to respond to the statement in the PFD. Nevertheless, after reviewing the ALJ's determination of certain issues in the PFD, the Company has now elected not to appeal the ALJ's evidentiary ruling.

### 3. Facilities and Shared Services Capital Expenditures

#### a. Control/Dispatch Centers

The Company is following through with its plan to consolidate dispatch operations. 3 TR 2157. In Case No. U-21389, the Company initially proposed, and the Commission approved, a

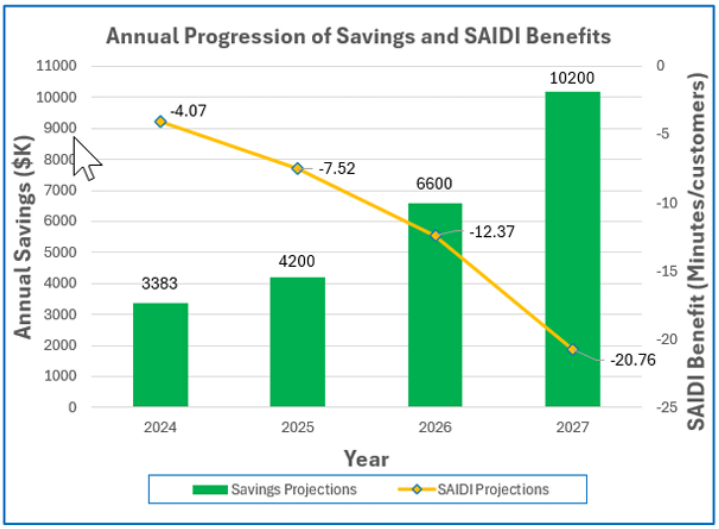
plan to consolidate control and dispatch operations into a single Control/Dispatch Center with another unstaffed, remote backup location. 3 TR 2159. But as part of a continuous-improvement process, which the Company calls "Plan, Do, Check, Act," it listened to coworker feedback that it risked losing talent if it pursued its original plan. 3 TR 2158. The Company listened to this feedback and acted decisively to correct course. While it did not retract its earlier assessment that consolidating operations into a single location would improve operations, after further review, it did determine that staffing the backup location would enhance its operational capabilities even more. So, in a smart move, the Company decided to staff the backup location as well – a decision that will further improve service, avoid additional costs, and lead to further SAIDI savings. The decision also changed the scope of the project and required a rate case update. *Id.*

Considering the project's expanded scope, Company witness Andrew R. Snider, Executive Director of Electric Operations, projected "a total expenditure of $30.7 million for this project, including $15.8 million in the test year ($15.5 million in capital and $308,000 in O&M)." 3 TR 2164. "These costs," he said, "support the completion of construction, commissioning, and occupancy of the operating control centers by early 2027, as well as the integration of support group operations within the consolidated control centers." *Id.*; Exhibit A-102 (QAG-3), Exhibit A-128 (MPK-18). Much of this work has already been completed. Mr. Snider described the milestones that the Company had achieved through 2024, including consolidating three dispatch centers into two facilities: one in Grand Rapids and one in Jackson, which absorbed Saginaw's functions. 3 TR 2160; Exhibit AG-22, page 2. The Company has also merged three operating groups into two (HVD and LVD operations) and redistributed operational roles and responsibilities for a smoother workflow. 3 TR 2160.

With work well underway, customers are reaping the benefits. According to Mr. Snider, "Customers have already benefited from $3.4 million of avoided costs and a 4.1-minute SAIDI [System Average Interruption Duration Index] reduction achieved during the transition and throughout 2024." 3 TR 2159. The Company had anticipated these savings, initially projecting that its plan to move to a single staffed control center, with an unstaffed backup, would "yield annual savings of $8.6 million and reduce SAIDI by 15 minutes." 3 TR 2159-2160. Even better, however, the current plan is "expected to yield annual savings of $10.2 million and reduce SAIDI by 20.8 minutes." 3 TR 2160.

The Company was able to update its projected benefits after reviewing historical data from 2022–2023 and analyzing the actual benefits from 2024. Whereas it earlier estimated a two-hour improvement to restoration times in gray-sky and catastrophic conditions, based on the additional data available in this case, it later projected a two-hour improvement in gray sky conditions and a *24-hour improvement* in catastrophic conditions. 3 TR 2163. Mr. Snider said that the Company would realize these benefits by March 2028, one year after the project is completed, and he prepared a graph illustrating how these benefits have grown and will continue to grow:

**Figure 7**
***Control/Dispatch Center Consolidation Project Annual Progression of Benefits***




3 TR 2162.

In terms of cost savings or avoided costs, Mr. Snider explained how its avoided costs benefit customers. After noting that "cost avoidance . . . is a valid and recognized planning metric in utility operations," he said that these avoided costs can be placed in one of three categories:

1. reduced service restoration expenses;
2. lower overtime and Incident Command System ("ICS") activation costs; and
3. efficiency gained from better coordination and situational awareness. 3 TR 2177.

As discussed above, in 2024 the Company already realized $3.4 million in actual avoided costs – a number that is only expected to grow as illustrated in the above graph.

Despite the SAIDI benefits and annual cost savings, some intervening parties recommended that the Commission disallow a large portion of the Control/Dispatch Consolidation Project's costs. The Attorney General was foremost among them, recommending that the Commission remove *all* the project's costs from the bridge year and test year. Staff recommended a lower, although still significant, disallowance – a 50% disallowance amounting to $2,435,500 in

the bridge period and $7,748,500 in the projected test year. With a focus on past spending for the project, Staff witness Jessica Duell reasoned that the Commission should disallow half of what the Company requested "[s]ince the Company underspent by nearly half of what was requested [in 2024] and included in the calculation of rates previously [in Case No. U-21585]." 6 TR 4400-4401.

The ALJ properly rejected the Attorney General's proposed disallowance but nonetheless adopted Staff's proposal. Although acknowledging that "[a]t least some progress appears to have been made to justify at least some spending in relation to the Control/Dispatch Center Consolidation Project," the ALJ found that "the Company appears to be underspending its capital expense projections, as presented by Staff." PFD, page 293. The ALJ then adopted Staff's recommended disallowance "to bring projected spending more in line with likely actual spending." *Id.* He did not evaluate why actual spending in 2024 diverged from past projections or explain why he believed the Company was "likely" to spend half of what it forecasted for the project except to rely on Staff's retrospective evaluation of past spending in a single year.

The Commission disallows projected costs for past underspending *only* when there is a pattern of underspending. See, e.g., MPSC Case No. U-18322, March 29, 2018 Order, page 60 ("Consumers has failed to spend the approved amount in this category *for several years*") (emphasis added). A single year of underspending does not justify a disallowance. See Case No. U-20836, November 18, 2022 Order, pages 211-212 (agreeing with the ALJ who, when discussing Staff's proposed disallowances for certain Plant and Field projects, found that "historical

underspending in one year, 2020, is not a sound basis to adjust [a utility's] 2021 projection in the absence of any other evidence that its 2021 estimate of actual 2021 spending is inaccurate.").[4]

Like Case No. U-20836, in the instant case, Staff's proposed disallowance was based on a single year of spending. See 6 TR 4400-4401. Unlike Case No. U-20836, however, the ALJ adopted the proposed disallowance. He should not have. There is no other evidence that forecasted spending will be less than projected. Ultimately, the funding requested for the bridge period and the test year is prudent, necessary, and aligned with strategic operational goals. These investments support reliability, resiliency, and best practices, providing geographic redundancy and business continuity.

Besides the Commission precedent, it is simply not reasonable to disallow funding for the Control/Dispatch Center Consolidation Project predicated solely on a single year of historical spending that overlooks the strategic evolution of the project. Mr. Snider explained that the Company decided to transition from a single Unified Control Center to a dual-location model while it was executing its plan. This change did not cause any rework. All previously completed engineering, design, and other work remained valid. The transition was managed without duplicative effort or additional cost. 3 TR 2179.

To the extent that the Company's 2024 spending is relevant at all, what should stand out about the Company's 2024 spending is that it had a good reason to spend less than projected. The Company spent less than expected in 2024 because it prolonged the design phase to incorporate the expanded scope. The projected capital expenditures naturally ramped up in the bridge period

[4] In Case No. U-20836, the Commission did disallow costs for a single cost category of Plant and Field projects, but this was because there was not enough evidence on the record to justify the projection – not because of a single year of historical underspending. See MPSC Case No. U-20836, November 18, 2022 Order, page 212.

in this case after the design phase was completed and the Company moved on to more capital-intensive work.

The Company cannot complete the project at half the estimated cost, so it urges the Commission to approve the full projected amount and recognize the long-term value of the Control/Dispatch Center transformation for the Company's customers. 3 TR 2181.

**4. Fleet Services Capital Expenditures**

**a. Vehicle Capital Expansion Plan**

The Company plans to invest $648,000 in the 12 months ending December 31, 2025, $15,170,000 in the 12 months ending December 31, 2026, and $46,070,000 in the test year to support workforce expansion efforts in Electric Operations. The workforce expansion helps address the Company's increasing investment in electric distribution infrastructure. See 3 TR 1379-1564. Although recognizing that it "seems unlikely that the Commission will reject the entirety of the undergrounding and LVD work," which is what the vehicle expansion costs are being proposed to support, the PFD at page 305 recommended adoption of the Attorney General's proposed disallowance of $27,931,000 for fleet expansion in the projected test year. If this recommendation is adopted, the Company risks stranding labor as some members of the Company workforce could be without equipment and vehicles necessary to perform the work if the workforce expansion efforts in Electric Operations are approved. While the PFD pointed to concern expressed by Staff for underground spending in 2025 as support for why the Company would not be able to scale up the work as proposed and require the additional vehicles (PFD, page 305), Staff did not oppose the Company's proposed vehicle expansion costs. This PFD's recommendation is

unsupported by the record, and the Company asks that the Commission approve its vehicle expansion plan and the associated costs.[5]

### 5. IT and Security Capital Expenditures

#### a. Overview and Expenditures

Company witness Stacy H. Baker described the Company's proposed capital expenditures for the IT Department and refuted intervening parties' proposed capital expenditure reductions. Staff largely supported the Company's proposed capital expenditures but recommended several reductions amounting to $1,056,334 for the historical test year that ended December 31, 2024, $3,550,316 for the 16-month projected bridge period ending April 30, 2026, and $2,675,579 for the projected test year. See Exhibit S-14.0. The Attorney General recommended far larger adjustments. Attorney General witness Sebastian Coppola proposed disallowing all costs for the S/4HANA project, amounting to $20,392,000 for the 16-month bridge period and $34,793,000 for the projected test year. 3 TR 796-797, 2502-2503. Mr. Coppola further recommended blanket adjustments for nine projects in the Investment Planning phase – amounting to $7,731,000 in the bridge period and $14,495,000 in the projected test year – and adjustments for the Asset Refresh Program ("ARP") Field Device Asset Management ("FDAM") – amounting to $1,039,000 in the bridge period and $2,513,000 in the projected test year.

The ALJ rightly recommended that the Commission reject nearly all of these proposed disallowances, see PFD, pages 312-366, but he supported a few adjustments that merit a brief response.

[5] Please also note that the revenue requirement impact of the PFD's recommended disallowance of Fleet expenditures is not correctly reflected in the PFD Appendices because a portion of depreciation expense related to Fleet is capitalized. If the Commission approves a disallowance of Fleet expenditures, which it should not, the revenue requirement impact would need to be corrected.

### (i.) Product Family Enhancements-Customer Projects

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. The Company must be agile in the current digital environment, and this funding will allow the Company to react in real time to avoid costs, improve safety, and provide excellent customer service. 3 TR 733; Confidential Exhibit A-21 (SHB-6), pages 118-129.

Staff proposed several adjustments to the Company's proposed capital expenditures for the Product Family Enhancement projects, and the ALJ recommended that the Commission adopt two of Staff's proposed adjustments, which the Company opposes.

#### (a.) Mobile App

In Case No. U-21389, the Commission approved the Company's Mobile App noting that:

> The Commission agrees with the company's arguments that, while there may be some redundancy in the functions of the app and the website, there is value in offering varying communication channels to meet customer needs. As pointed out by Consumers in its exceptions, it could be argued that there is redundancy between the functions of call centers and the company's website as both are avenues to receive customer payment. As technologies and customer preferences evolve, the Commission finds that duly supported, reasonable, and prudent expenditures to meet those preferences are appropriate for recovery. [MPSC Case No. U-21389, March 1, 2024 Order, page 83.]

The PFD recognized that the Commission has rejected the argument that the Mobile App funding should be disallowed due to being redundant to the website. See PFD, page 338. Despite this, the PFD found that in Case No. U-21806, the Commission indicated that "the emergent costs that the Mobile App spending represented were akin to contingency expenses that cannot be evaluated for

reasonableness and prudence, leading to the disallowance of spending in that case." PFD, page 338 (citing U-21806 Order, pages 137-139.) Based on this reasoning, this PFD recommended a disallowance of $1,056,334 for 2024 and $1,305,671 for 2025 related to various enhancements for the Company's Mobile App. PFD, page 338.

The PFD's reasoning is inappropriate as it disallowed actual costs claiming that reasonable and prudence of these expenditures cannot be determined because it is "too speculative to determine whether the projected spending is likely to be reasonably and prudently spent." PFD, page 338. The costs that the PFD recommended being disallowed are not "emergent" and were not related to projected spending. These enhancements undertaken were necessary updates for the Company to maintain the app. Investment into these enhancements ensures these tools work as requested. 3 TR 967.22-967.23. The Company provided a detailed list of the work undertaken. This information was included in Exhibit S-10.2. Thus, recovery of these reasonable costs to maintain the mobile app is appropriate and the PFD's recommendation should be rejected.

**(b.) Web Chat AI**

The Web Chat AI tool is an alternative to calling a service center. Chat functionality engages and allows the customer to chat with an AI tool to find answers to questions or concerns. Exhibit S-10.12. This is an added functionality that differs from chat tools that allow customers to chat with a person. The tool will be able to rapidly respond to customer inquiries with specific information related to the customer's unique situation.

The PFD recommended a disallowance of $157,574 in capital expenditures for the partial bridge year ending April 30, 2026, $315,148 in capital expenditures for the partial year ending December 31, 2026, and a disallowance of $19,896 in O&M expense associated with the Web

Chat AI tool. PFD, page 355. The PFD found the tool to be redundant and argued that it is unclear who, if anyone, is actually being helped with this spending. PFD, page 355.

An AI chat tool is not the same thing as a frequently asked questions page, but an experience that more closely simulates speaking with a Company employee. An AI chat tool can quickly retrieve relevant information tied to specific customer inquiries. It goes far beyond merely making information available and would allow customers to resolve specific inquiries without searching through common inquiries that may or may not be directly relevant to their situation. This tool is not intended to have all the functionality of the Company's website, nor is it intended to replace it. Investments in Web Chat AI are an important front-end enhancement to provide better service to customers, increase access to assistance and programs, and overall help customer self-service more effectively within this digital channel. 3 TR 967.53. Thus, the Web Chat AI costs should be approved.

**(ii.) Projects in the Investment Planning Phase**

Attorney General witness Coppola recommended that the Commission adjust the Company's proposed capital expenditures for two groups of supposedly premature IT projects. The first group includes four projects in the Investment Planning phase of development: (1) the Electric Geographic Information System ("GIS") Design Platform Modernization project; (2) the Electric GIS Utility Network Transformation project; (3) the Integrated Energy Management Platform Optimization project; and (4) the Service Restoration Artificial Intelligence project. 3 TR 2497. The second group includes five projects also in the Investment Planning phase of development: the Critical Substation Upgrade project, the Data & Analytics Platform Rationalization project, the Operational Technology Datacenter Migration project, the Forward Web Proxy Services project, and the Physical Access Management and Alarm Response. 3 TR

2498. Mr. Coppola reasoned that projects in the Investment Planning phase have "detailed requirements" that have yet to be completed, and he argued that "[t]hese projects are still in the initial stage of development and significant uncertainty remains whether or when they will advance further." 3 TR 2497-2498.

The ALJ rejected the Attorney General's proposed adjustments with two exceptions: the Electric GIS Utility Network Transformation project and the Integrated Energy Management Platform Optimization project. According to the ALJ, while the Company "generally supported" the need for these projects, they "are premature based on Consumers' indication that it does not plan to expend funds for these projects until 2027, the last four months of the test year." PFD, page 366. As a result, the ALJ recommended that the Commission reject proposed expenditures for the "Electric GIS Utility Network Transformation ($1,050,000 capital and $520,000 O&M) and Integrated Energy Management Platform Optimization ($1,075,000 capital and $508,000 O&M) projects, resulting in a recommended disallowance of $2,125,000 in capital expenditures and $1,028,000 in O&M expenses for the projected test year." *Id.*

The Company respectfully takes exception to these proposed disallowances. Whether the Company makes the expenditures in the first four months of the test year, the last four months of the test year, or the last day of the test year does not determine whether a project is premature. Significant work has been done and is planned for the projected test year. IT business cases were completed and approved for the two projects, which required significant "requirement work." 3 TR 787, 790. As part of this work, the Company describes each project and its functionality; project timelines with expected implementation dates; spending plans, project benefits, and cost-benefit ratios; and alternatives considered, explaining why the Company chose the proposed project over alternatives. 3 TR 674. As part of this process, the Company also identifies

performance and security requirements, determines whether the functionality needed is already present in the Company's IT environment, and works with software vendors and cloud solution providers to evaluate their products and services. 3 TR 674-675.

Without any other stated basis on which to oppose the expenditures (except that they occur in the latter half of the test year), they should be approved. The expenditures are well supported on the record. Company witness Michael P. Kelly described the need for the Electric GIS Utility Network Transformation project, which will transform the Company's current GIS platform into a unified HVD, LVD, and substations data model. 3 TR 1490-1492. At the same time, Company witness Megan L. Metz described the need for the Integrated Energy Management Platform Optimization project, which will reduce the number of data center assets running on the PCI platform (a platform used to communicate unit availability to MISO) by migrating from on-premise servers to cloud services. 3 TR 1795-1797. Support for the projects can also be found in Exhibits A-12 (SHB-4), line 3; A-19 (SHB-3), line 1; and A-21 (SHB-6), pages 62-63 and 101-102.

The Attorney General's sole reason for recommending that the Commission disallow expenditures for these projects is that they are in the investment planning phase and that "detailed requirements have yet been completed." 3 TR 2497. The ALJ rejected the same arguments for other projects, disagreeing with the Attorney General that "a project in the investment planning phase is per se premature." See PFD, page 365. The only difference between the two projects at issue and the other projects the ALJ recommended approving is that the two projects do not have planned 2026 expenditures.

The lack of 2026 expenditures is not a reason to reject the projects as premature when they have planned test year expenditures in 2027. The Company is not requesting recovery for post-

test year expenditures. This is evident when comparing the total 2027 expenditures for these projects shown in Exhibit AG-28 with the projected test year expenditures shown in the same exhibit.

The Commission should reject the ALJ's recommendation to disallow $2,125,000 in capital expenditures and $1,028,000 in O&M expenses for the Electric GIS Utility Network Transformation project and the Integrated Energy Management Platform Optimization project.

### 6. Transportation Electrification Plan Capital Expenditures and Enhancements

Consumers Energy witness Jeffrey A. Myrom described the Company's three EV programs: (1) PowerMIDrive Residential, which targets single-family and multi-family off-peak charging; (2) PowerMIDrive Public, which promotes off-peak charging at strategic locations like hotels, campgrounds, conference centers, and long-term parking lots; and (3) PowerMIFleet, which promotes fleet and workplace off-peak charging at businesses, local governments, non-profits, and educational institutions among others. 3 TR 1864-1868. Collectively, these EV programs are known as the Company's Transportation Electrification Programs ("TEPs").

Mr. Myrom proposed two enhancements to the TEPs. The first will provide customers with a bring-your-own-cord option to reduce costs and maintenance. The second continues Direct Current Fast Charging ("DCFC" or "fast charging") rebates for a limited time. 3 TR 1871-1872. The ALJ recommended that the Commission approve the Company's proposed enhancements. PFD, page 404. The ALJ also recommended that the Commission approve a Staff recommendation, which the Company agreed to, and that the Commission note several stipulations made during the course of this case. *Id.* at 404-405. Otherwise, the ALJ recommended that the Commission reject most of the intervening parties' other requested TEP changes.

The ALJ found, however, that Mr. Myrom's definition of "community" could be improved and that the criteria the Company uses to evaluate rebate applications could also be improved. PFD, page 405. The Company defined "community" and provided its rebate application criteria during this case. See Exhibit A-223 (JAM-4) and A-224 (JAM-5). A broad definition of community gives the Company flexibility when evaluating rebate applications, and the criteria it uses when considering whether to grant a rebate are already robust. The Commission should reject the ALJ's recommendation and respect the Company's management prerogative.

## III. CAPITAL STRUCTURE AND RATE OF RETURN

### A. Common Equity Ratio

The PFD recommended that the Commission reject Consumers Energy's request for an equity ratio of 50.75% and instead maintain an equity ratio of approximately 50% in this case. PFD, page 448. The ALJ does not really explain his reasoning other than to say that he finds that Consumers Energy "has not established that its request . . . is reasonable and consistent with prior Commission orders." PFD, page 448. Since the ALJ offered no specific reasons why the Company's presentation was insufficient, the Commission should give no weight to his recommendation.

The Company's equity ratio (together with its ROE) have an important impact on the Company's credit quality. 3 TR 818-825. This occurs in two ways. First, both the equity ratio and the Company's ROE are included in a key financial metric used by credit rating agencies to evaluate a business's credit quality – the ratio of the business's Funds from Operations ("FFO") to the business's debt ("FFO-to-Debt ratio"). 3 TR 818. Second, credit rating agencies also evaluate the regulatory environment in which a utility operates as part of their determination of a utility's credit quality. 3 TR 824. The authorized equity ratio and ROE are two important components in

the rating agencies' assessment of the regulatory environment. 3 TR 824. Company witness Marc R. Bleckman explained that, if the Commission demonstrates a pattern of consistent, constructive rate orders, it contributes favorably to the Company's credit quality and credit rating. 3 TR 824. The converse is also true. If the Commission demonstrates a pattern of inconsistent or non-constructive rate orders, it contributes unfavorably to the Company's credit quality and credit rating.

It is important to recognize that the Company's equity ratio and ROE cannot be evaluated in isolation. 3 TR 819. Instead, the Commission should calculate the weighted rate of return by multiplying the equity ratio and ROE together. 3 TR 819. Mr. Bleckman showed that the Company's weighted rate of return has been declining as a result of declining equity ratios over the last five years. 3 TR 820. This trend has also corresponded to the Company's declining ratios of FFO-to-Debt with Moody's Investors Service's ("Moody's") and S&P Global Market Intelligence ("S&P") over the same period. 3 TR 820-821. The Company's FFO-to-Debt metrics are now below the low end of S&P's and Moody's expected ranges and approaching their downgrade thresholds. 3 TR 820-821. Similarly, Mr. Bleckman noted that both S&P and UBS have recently downgraded the Commission's regulatory environment score due to unfavorable perceptions of the Commission's recent ratemaking decisions as they pertain to equity ratios and ROEs. 3 TR 824-825. Both of those conditions will undoubtedly become markedly worse if the Commission were to approve rates in this case based on the ALJ's recommendation of a 50% equity ratio and a dramatically reduced 8.2% ROE.[6]

Mr. Bleckman testified that, in February 2024, S&P updated its credit outlook for the North American regulated utility industry as a whole to negative, and that in January 2025, S&P again

[6] The Company discusses the critical need to reject the ALJ's ROE recommendation in more detail in the next section of these Exceptions.

highlighted the problem that "a high percentage of companies are operating with only minimal financial cushion from our downgrade threshold." 3 TR 825-826. S&P specifically identified the need for "significantly more common equity issuance" to avoid weakening financial measures across the industry. 3 TR 826. Furthermore, Mr. Bleckman testified that a high degree of volatility and economic uncertainty has emerged in recent months with respect to financial markets, interest rates, and geopolitical tensions. 3 TR 821. Mr. Bleckman pointed to such factors as Trump administration trade policies and elevated input costs for businesses reliant on global supply chains, which have contributed to a recent peak in a key stock market index of market volatility. 3 TR 821-822. Mr. Bleckman explained that, during this period of heightened risk and volatility, it will be critical for the Company to have an authorized ROE and equity ratio that is supportive of its good credit quality and will be instrumental in the Company's ability to maintain uninterrupted access to needed liquidity and better withstand potential impacts from fuel price spikes, inflationary pressures, and tightening capital markets. 3 TR 822. In light of these risks, it is important for the Company to maintain strong financial metrics and to not manage toward the perceived low end of the credit metric bands. 3 TR 826-827. Prudent financial management requires that the Company maintain a modest financial cushion above credit rating agency downgrade thresholds "to protect against downgrade in the event of unforeseen events like the market volatility and disruption that occurred during the onset of the COVID-19 pandemic in 2020 or the financial pressure caused by the dramatic increase in gas prices and interest rates in 2022 or the banking crisis of 2023." 3 TR 826. The Company's ability to continue to provide customers with safe, reliable, and clean energy and make the necessary capital investments is directly tied to the Company's ability to maintain its financial strength. 3 TR 827.

Perhaps the best objective evidence supporting the reasonableness of increasing the Company's equity ratio was Mr. Bleckman's analysis showing that peer utilities currently have meaningfully higher equity ratios than Consumers Energy has proposed in this case and that they are trending upward. 3 TR 815-818. Mr. Bleckman provided an analysis of the actual ratemaking equity ratios set by regulatory agencies for the regulated subsidiaries of the Company's ROE proxy group. 3 TR 815. The average equity ratio for the peer group was 51.85%, which is 110 basis points higher than the 50.75% proposed for Consumers Energy in this case. 3 TR 816. These peer results show that the Company's proposed equity ratio in this case is well justified and, in fact, quite conservative.

Finally, it is important for the Commission to keep in mind that a constructive equity ratio, supporting a higher credit rating for the Company, benefits customers. The Company provides a critical service that directly impacts customers' quality of life, but 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 and strong credit rating of the Company. 3 TR 822. The Company is making significant capital investments to maintain and improve infrastructure to the benefit of customers. The Company will rely heavily on the capital markets to fund these investments. 3 TR 823. Mr. Bleckman explained that, generally, a higher credit rating results in lower financing rates. 3 TR 823. Therefore, it will be especially important for the Company to maintain strong credit ratings over this period. Mr. Bleckman sponsored Exhibit A-32 (MRB-13), which shows that the Company has saved customers $152 million annually as a result of improved credit ratings and lowered interest costs. Mr. Bleckman also explained that a constructive equity ratio enables the Company to better withstand any shocks in the financial markets. 3 TR 823. 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 investments on behalf of customers. 3 TR 823. Finally, he testified that strong credit ratings can also enable the Company to issue long-term debt ahead of upcoming maturities (i.e. pre-fund) to take advantage of low interest rates and favorable issuance windows without jeopardizing the Company's financial ratios. 3 TR 823. 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. 3 TR 823.

The ALJ's claim that the Company's proposed equity ratio in this case is inconsistent with Commission precedent is not correct. Consumers Energy acknowledges that, beginning in 2017, in Case No. U-17990, the Commission expressed its desire to move Consumers Energy toward an evenly balanced 50% equity ratio based on the record in that case. MPSC Case No. U-17990, February 28, 2017 Order, page 64. At the time, the Company's equity ratio had been increasing over several cases, approaching 53%, and the country was experiencing historically low interest rates. *Id*. at 63. However, the Commission in Case No. U-17990 did not take the position that a 50% equity ratio is required under all circumstances. Instead, the Commission has always taken the position that the appropriate equity ratio must be based on a review of the facts of each case and that an equity ratio above 50% may be justified when the facts warrant it. The Commission emphasized this view in its Order in Case No. U-20963, where the Commission wrote:

> [T]he Commission has also sought to maintain some degree of flexibility to accommodate the specific circumstances connected with a utility's investment plans and elements of its balance sheet. On this basis, as noted by the ALJ, the Commission has shown a "willingness to accept a temporary deviation from a balanced capital structure over the short term" when circumstances warrant such an approach. PFD, p. 284. In addition, the Commission has also provided a utility with the opportunity to put forth "a more complete analysis . . . to explain why such a result [of deviating from a 50/50 capital structure] is reasonable and prudent." February 28 order, p.

> 64. As such, the Commission maintains its goal of a capital structure evenly balanced between debt and equity, while continuing to allow a utility to present arguments why a deviation from this ratio is appropriate. As it has done in previous rate cases, the Commission will continue to consider all evidence and circumstances in each rate case to determine the appropriate capital structure. [MPSC Case No. U-20963, December 22, 2021 Order, page 200. (Editing marks in original).]

In Case No. U-17990, the Commission expressed its understanding that an unduly low equity ratio could detrimentally impact Consumers Energy's access to capital, "particularly in times of heavy infrastructure investment cycles." MPSC Case No. U-17990, February 28, 2017 Order, page 64. In Case No. U-17990, the Commission relied on the Company's testimony that it was then implementing "a five-year period of significant infrastructure investments." *Id*. Accordingly, the Commission approved an equity ratio of 52.87% in that case, but directed the Company to "return to, a balanced structure within the five-year infrastructure plan time period." *Id*. at 64. That process of returning to an evenly balanced capital structure was essentially completed in Case No. U-21389. See MPSC Case No. U-21389, March 1, 2024 Order, page 129.

The Company is currently in a "heavy infrastructure investment cycle." In Case No. U-17990, the net utility plant amount approved by the Commission was $9.4 billion. MPSC Case No. U-17990, February 28, 2017 Order, page 60. In this case, the Company continues to make additional heavy infrastructure investments bringing the net utility plant amount up to $13.2 billion. See Exhibit A-209 (PDD-64). Even if the Commission were to adopt all of Staff's adjustments to the Company's rate request, the net utility plant would amount to $13.1 billion. See Exhibit S-2, Schedule B-1. By any measure, the Company's infrastructure investments have increased net utility plant by approximately 40% since Case No. U-17990, even after accounting for eight years of depreciation. Company witness Bleckman testified that the weighted rate of return as proposed in this case, including a 50.75% equity ratio, "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." 3 TR 879.

There are additional reasons supporting a modest increase in the equity ratio in this case. Company witness Bleckman testified that a severe drop in the stock market in early April of this year and the recent federal government shutdown, in addition to ongoing conflicts such as those in the Middle East and between Russia and Ukraine and other geopolitical uncertainty that continue to elevate risk and volatility to U.S. markets, represent material changes in the Company's risk environment since the previous Commission orders. 3 TR 880. Mr. Bleckman expects this elevated risk and volatility environment to continue into the test year in this case. 3 TR 880. As a result, Mr. Bleckman testified that the Company's proposed equity ratio "will be instrumental in the Company's ability to maintain uninterrupted access to needed liquidity and better withstand potential impacts from fuel price spikes, inflationary pressures, and tightening capital markets." 3 TR 880.

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. The Company's proposed 50.75% equity ratio is important to ensure that the Company will have access to the capital needed for these investments and to protect the Company's credit quality so that it can access that capital and reasonable rates. The Commission's criteria for adopting an equity ratio modestly over 50% are easily satisfied under the conditions presented in this case.

Contrary to the ALJ's unexplained finding, the Company's testimony and exhibits demonstrate 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 common equity

balance for the test year of $13.916 billion, its long-term debt balance for the same period of $13.465 billion, and the resulting equity ratio of 50.75%. Exhibit A-14 (MRB-1), Schedule D-1, page 1 (See also Exhibit A-14 (MRB-2), Schedule D1a, pages 1 and 3).

### B. Return on Equity

The most significant and most concerning error in the PFD was the ALJ's analysis and recommendation for the ROE to use in setting rates for this case. If the Commission were to adopt the ALJ's recommendation of an 8.2% ROE, it would have a catastrophic impact on the Company's credit rating and its ability to attract capital on favorable terms to finance the Company's significant investment needs. It would also result in an immediate reevaluation of the regulatory environment in Michigan by credit rating agencies and equity analysts,[7] and would likely have detrimental impacts on all utilities in Michigan. The ALJ's recommendation was radically lower – more than 100 basis points lower – than the lowest ROE recommendation offered by any party to this case. His recommendation was based on both faulty legal reasoning and an incorrect analysis of the evidence. The Commission must reject the ALJ's ROE recommendation.

#### 1. The ALJ Misread U.S. Supreme Court Precedent and Applied a Legal Standard for Determining ROE That Does Not Exist

The ALJ based his ROE recommendation heavily on an incorrect interpretation of the U.S. Supreme Court's holding in an obscure 1909 case: *Willcox v Consol Gas Co of New York*, 212 US 19; 29 S Ct 192; 53 L Ed 382 (1909) (the PFD incorrectly refers to the case by the name *Wilcox*

[7] The investment community reacted swiftly and negatively to the ALJ's ROE recommendation, which had immediate impacts on both Consumers Energy's and DTE's stock prices. Financial market analysts have cautiously recommended that investors remain calm, trusting the Commission's more moderate track record. Nevertheless, they express concerns that "the headline will likely weigh on Michigan utilities until the case is adjudicated" and that "the volatility and uncertainty [caused by the 8.2% ROE recommendation] is fraying investor confidence in Michigan as a premium jurisdiction." See the January 30, 2026 equity analyst reports by BMO Capital Markets Corp. and Jefferies LLC/Jefferies Research Services, LLC (attached to these Exceptions as Attachments A and B, respectively). These attachments are not being offered as "evidence" in this case, but merely to provide the Commission with contextual background for its policy consideration.

throughout). The ALJ confused the U.S. Supreme Court's standards articulated in *Willcox* with the U.S. Supreme Court's subsequent application of those standards to the facts of that particular case. The ALJ's misreading of *Willcox* and the faulty legal reasoning based on it ultimately led the ALJ to assert the existence of a legal standard that does not exist. The ALJ then applied this fictitious legal standard to conclude that the results of the traditional quantitative ROE models in this case are constitutionally prohibited as too high and to recommend a reduction in ROE that defies all of the requirements of the real constitutional standards for an appropriate return recognized by the U.S. Supreme Court for roughly 100 years.

Despite the ALJ's heavy reliance on *Willcox* in this case, *Willcox* is not typically cited by courts, regulatory commissions, or legal practitioners in the field as the clearest articulation by the U.S. Supreme Court of the constitutional standards for a permissible ratemaking return. The Supreme Court's clearest and most cited statements regarding the correct standards for setting a constitutionally sufficient return were articulated in *Bluefield Waterworks & Imp Co v Pub Serv Comm of W Va*, 262 US 679; 43 S Ct 675; 67 L Ed 1176 (1923) and *Fed Power Comm v Hope Natural Gas Co*, 320 US 591, 603; 64 S Ct 281; 88 L Ed 333 (1944). The Supreme Court stated in *Bluefield*:

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

Similarly, the Supreme Court stated in *Hope*:

> By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the

> enterprise so as to maintain its credit and to attract capital. [320 US at 603. Emphasis added.]

These landmark Supreme Court decisions identify three criteria that a legally sufficient rate of return must satisfy in order to be regarded as minimally constitutionally sufficient: (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. Although the PFD does cite and discuss the standards identified in *Bluefield* and *Hope* to some extent, the ALJ places disproportionate emphasis on *Willcox* in his analysis because it is through a misreading of *Willcox* that the ALJ derives his understanding of a supposed constitutional standard not found in *Bluefield* or *Hope*.

There are two important things to note here. First, under *Bluefield* and *Hope*, the amount of risk that a business faces *is* a relevant part of the inquiry into the proper return that is required under the U.S. Supreme Court's constitutional standards, *but* it is only one of the considerations, and the Supreme Court did not identify risk alone as superseding the other requirements. Second, the Supreme Court did not in *Bluefield* or *Hope* claim that the Constitution assigns, as a matter of law, any particular level of "risk" to public utilities as a class merely because they are public utilities or even assume that all public utilities share the same amount of risk. Instead, the Supreme Court recognized that each different utility may have different levels of risk and the return used to set rates should correspond to that risk, i.e. the return should be comparable to other companies (not necessarily utilities) with similar risk.

In *Willcox*, the Supreme Court articulated the same standards regarding the constitutional requirements for the rate of return used to set rates in a regulatory proceeding as follows:

> There is no particular rate of compensation which must, in all cases and in all parts of the country, be regarded as sufficient for capital invested in business enterprises. Such compensation must depend greatly upon circumstances and locality; among other things, the amount of risk in the business is a most important factor, as well as the locality where the business is conducted, and the rate expected and usually realized there upon investments of a somewhat similar nature with regard to the risk attending them. There may be other matters which, in some cases, might also be properly taken into account in determining the rate which an investor might properly expect or hope to receive and which he would be entitled to without legislative interference. The less risk, the less right to any unusual returns upon the investments. One who invests his money in a business of a somewhat hazardous character is very properly held to have the right to a larger return, without legislative interference, than can be obtained from an investment in government bonds or other perfectly safe security. [*Id*. at 48-49.]

These standards are consistent with the standards articulated in *Bluefield* and *Hope*. Furthermore, nothing in these standards contradicts the two points discussed above: (i) risk is one consideration among others; and (ii) there is no particular rate of return that can be regarded as sufficient in all cases and all parts of the country for utilities as a class.

After articulating those standards, the U.S. Supreme Court in *Willcox* then proceeded to apply the constitutional standards to the case before them, i.e. to the specific circumstances of Consolidated Gas Company of New York in 1909. Understanding the facts of *Willcox* is vital to understanding the Court's application of the constitutional return standard to the circumstances of Consolidated Gas Company of New York. Between 1823 and 1884, New York City had seven gas utilities operating within the city under separate charters. *Id*. at 42. Each of the seven gas utilities had a specific, defined service territory within the city. *Id*. at 43. Collectively, those seven gas utilities had "a capacity capable of supplying the demands for the next twenty years," and there was a law on the books that "virtually prohibited the laying of any more gas pipes in the streets." *Id*. at 46. Beginning in 1884, either the city or the state (it is unclear from the context of the Court's opinion) enacted a law to facilitate the consolidation of one or more of the existing gas utilities.

*Id*. at 43. Consolidated Gas Company of New York was formed by the consolidation of six of the seven original gas utilities. *Id*. From 1823 to 1905, the seven gas utilities (and, after 1884, Consolidated Gas Company of New York) were also entirely free of rate regulation and had, on average, been paying dividends to their shareholders of over 16%. *Id*. at 24, 45-46. During the consolidation process, the gas utilities were free, by agreement, to establish the valuation of their respective properties, and correspondingly, the collective value of the consolidated utility. *Id*. at 43. In 1905 and 1906, New York enacted new laws allowing for regulation of the utilities' rates. *Id*. at 24. Much of the dispute in *Willcox* related to the value placed on the utility's franchise with the city as a result of that self-valuation process and, by extension, whether the rates set by state law and the New York Gas Commission after 1905 and 1906 resulted in a return so low as to be confiscatory. *Id.* at 43-45. In applying the constitutional standards above to these facts, the U.S. Supreme Court wrote:

> The man that invested in gas stock in 1823 had a right to look for and obtain, if possible, a much greater rate upon his investment than he who invested in such property in the city of New York years after the risk and danger involved had been almost entirely eliminated.
>
> In an investment in a gas company, **such as complainant's**, the risk is reduced almost to a minimum. It is a corporation which, in fact, as the court below remarks, monopolizes the gas service of the largest city in America, and is secure against competition **under the circumstances in which it is placed**, because it is a proposition almost unthinkable that the city of New York would, for purposes of making competition, permit the streets of the city to be again torn up in order to allow the mains of another company to be laid all through them to supply gas which the present company can adequately supply. And, so far as it is given us to look into the future, it seems as certain as anything of such a nature can be, that the demand for gas will increase, and, at the reduced price, increase to a considerable extent. An interest in **such a business** is as near a safe and secure investment as can be imagined with regard to any private manufacturing business, although it is recognized at the same time that there is a possible element of risk, even in **such a business**. **The court below regarded it as the most favorably situated gas business in America**, and added that all gas business

> is inherently subject to many of the vicissitudes of manufacturing. **Under the circumstances**, the court held that a rate which would permit a return of 6 per cent would be enough to avoid the charge of confiscation, and for the reason that a return of such an amount was the return ordinarily sought and obtained on investments of that degree of safety in the city of New York. [Id. at 49-50 (emphasis added).]

In his PFD, the ALJ quoted a small portion of the long quote above[8] as support for his claim that "[t]he Supreme Court described the nature of the business model risk (or lack thereof) relevant to establishing a reasonable return as being based upon public utilities selling a necessary product – energy, power, light, heat – without competition pursuant to a state regulated monopoly." PFD, pages 523-524. In other words, the ALJ claims that the quoted language above was meant to establish a rule of law about the "nature of the business model risk" applicable to all utilities rather than simply applying the law to the specific and unique facts of that case. That is a misreading of the opinion. Nothing in the *Willcox* opinion supports the supposed rule of law that the ALJ draws from it.

First, as the longer quoted version shows, the Supreme Court didn't base its application of the constitutional standards in the *Willcox* case on the fact that the utility was "selling a necessary product." The Supreme Court really didn't discuss that aspect of the Consolidated Gas Company of New York's business at all. Second, and much more importantly, the Supreme Court never said that this portion of its opinion was meant to establish "the nature of the business model risk . . . relevant to establishing a reasonable return" for all utilities universally. This portion of the Supreme Court's opinion was clearly only discussing Consolidated Gas Company of New York

[8] Specifically, the following portion:

> In an investment in a gas company, such as complainant's, the risk is reduced almost to a minimum. It is a corporation which, in fact, as the court below remarks, monopolizes the gas service of the largest city in America, and is secure against competition under the circumstances in which it is placed . . . . [*Id.* at 49.]

and applying the general constitutional principles discussed earlier to the specific facts of that utility. The Supreme Court did evaluate the Consolidated Gas Company of New York's risk as being "reduced almost to a minimum" due in part to its lack of competition, but the Court also emphasized that the Consolidated Gas Company of New York enjoyed a level of insulation from competition that is unusual even among public utilities. It was, the Court acknowledged, "the most favorably situated gas business in America." The Supreme Court's discussion above repeatedly used language indicating that it was directed only at the specific utility that was a party to the case and to the unique facts and circumstances of that utility's operations. The Supreme Court states no generalized application to all utilities in this quote. It is applicable to other utilities only to the extent that they are factually indistinguishable from Consolidated Gas Company of New York in that case. The Supreme Court never said that the business risk of all utilities was "reduced almost to a minimum" as a class and in all cases.

Not all utilities are like Consolidated Gas Company of New York as it existed in New York City in 1909 – and the Supreme Court never said they were. Not all utilities operate in the "largest city in America." *Willcox*, 212 US at 49. Not all utilities are "secure against competition" because the "proposition [is] almost unthinkable that the city of New York would, for purposes of making competition, permit the streets of the city to be again torn up in order to allow the mains of another company to be laid all through them to supply gas which the present company can adequately supply." *Id*. Keep in mind that, in that case, the utility already had sufficient facilities to serve all local needs for at least 20 years and a local law that effectively prohibited any new utility infrastructure from being installed. Not all utilities can be characterized as "the most favorably situated gas business in America." *Id*. Consumers Energy's electric utility certainly does not enjoy any of those distinctions. The Supreme Court determined, *under the facts of that case*, that

Consolidated Gas Company of New York was uniquely less risky even compared to other public utilities. It was those unique features, discussed at length by the Supreme Court in that case, that rendered the Consolidated Gas Company of New York as having "minimum" risk – not some features common to all utilities. The ALJ read the holding of *Willcox* much too broadly.

Nevertheless, as a result of his misreading of the Supreme Court's opinion, the ALJ incorrectly concluded that the risk of all public utilities, as a matter of law, must be regarded as "reduced almost to a minimum" because all utilities sell a necessary product and enjoy regulated protection for their service territory that limits competition. The Supreme Court simply did not say that, nor did it identify those attributes as decisive in Consolidated Gas Company of New York's case. The ALJ improperly converts the factual findings in *Willcox*, and the application of the law to those facts, as if they were themselves a new conclusion of law. They were not. The application portion of the Supreme Court's decision in *Willcox* was solely directed toward a *specific* gas utility "such as complainant's [i.e. such as Consolidated Gas Company of New York]." Consumers Energy is not such a utility.

Perhaps the best evidence that the ALJ has badly misread *Willcox* comes from the U.S. Supreme Court itself in the landmark *Bluefield* case. Unlike *Willcox*, *Bluefield* is one of the two cases routinely cited by courts, regulatory commissions, and legal practitioners in the field of public utility ratemaking regarding the correct legal standard for determining a constitutionally sufficient return. The Supreme Court in *Bluefield* offered its own summary of the opinion in *Willcox*, which does not support the supposed standard claimed in the PFD. The *Bluefield* Court's summary correctly separates the rule of law articulated in *Willcox*, on the one hand, from the holding as applied to the facts of that case, on the other hand. The *Bluefield* Court wrote:

> In 1909, this court, in Willcox v. Consolidated Gas Co., 212 U. S. 19, 48–50, 29 Sup. Ct. 192, 53 L. Ed. 382, 15 Ann. Cas. 1034, 48 L.

> R. A. (N. S.) 1134, held that the question whether a rate yields such a return as not to be confiscatory depends upon circumstances, locality and risk, and that no proper rate can be established for all cases; and that, under the circumstances of that case, 6 per cent. was a fair return on the value of the property employed in supplying gas to the city of New York, and that a rate yielding that return was not confiscatory. In that case the investment was held to be safe, returns certain and risk reduced almost to a minimum—as nearly a safe and secure investment as could be imagined in regard to any private manufacturing enterprise. [Id. at 693. Emphasis added]

In *Bluefield*, the Supreme Court concluded that a return of 6% for Bluefield Waterworks was too low and, hence, confiscatory. Clearly, the Supreme Court understood the standard from *Willcox* to be that the proper return in any given case "depends upon circumstances, locality and risk, and that no proper rate can be established for all cases" because it arrived at a different outcome in *Bluefield* than it did in *Willcox*, even though both cases involved regulated public utilities. The Supreme Court in *Bluefield* clearly understood that the risk assessment for the Consolidated Gas Company of New York in *Willcox* was based on "the circumstances of that case" and that "in that case" the utility was held to be very low risk such that a 6% return was sufficient. The *Bluefield* Court did not claim that *Willcox* stood for the proposition that all utilities have minimal risk because they sell a necessary product or are insulated from some amount of competition. In fact, in *Bluefield*, the Supreme Court implicitly assessed the risk for Bluefield Waterworks as higher than the *Willcox* Court assessed Consolidated Gas Company of New York's risk to be and concluded that the same 6% return in the *Bluefield* case was confiscatory.[9]

[9] There is another important thing to recognize about the *Willcox* and *Bluefield* cases. The "return" that the U.S. Supreme Court evaluated in both of those cases was the overall rate of return approved by the regulators in those cases – not just the return on common equity. In this case, the PFD recommended an overall return of just 5.39% compared to the 6% return that the Supreme Court regarded as constitutionally sufficient in *Willcox*. See PFD, Appendix D, line 10, column (g). If the ALJ really believed that *Willcox* had established some kind of absolute standard regarding the risk attributable to all public utilities and, correspondingly, the return that is appropriate for those utilities, then the ALJ should have been concerned that his recommended overall return was lower than the one found appropriate in *Willcox*. The ALJ doesn't seem to have felt restrained from deviating too low, even though the constitutional standard is meant to establish a floor below which a ratemaking return becomes confiscatory.

Having erroneously concluded that *Willcox* established a legal standard that essentially holds that all public utilities' risk is "reduced almost to a minimum," the ALJ then reasons that "regulated utilities are not entitled to returns commensurate with or more than returns on investments in other enterprises having greater risks – such as the riskier businesses in the general market." PFD, page 525. Just as the Supreme Court in *Willcox* never said that all utilities must be regarded as having risk "reduced to almost a minimum," the *Willcox* Court also never said (or even suggested) that businesses in the "general market" are always riskier than utilities or that utilities' returns should always be lower than the returns of the "general market." In fact, the Supreme Court's opinion in *Willcox* doesn't mention the "market" at all. Nevertheless, the ALJ claimed that "the Supreme Court standards require that authorized ROEs be set at a level of returns which are less than the returns for the general market." PFD, page 525. Later in the PFD, the ALJ morphed this supposed legal requirement further by stating that "the Supreme Court standards require that authorized ROEs be set at a level of returns which are less than the <u>expected</u> returns for the general market." PFD, page 529 (emphasis added). There is no U.S. Supreme Court case that says anything of the kind. The ALJ created this standard out of thin air based on his erroneous reading of the *Willcox* case. There is no such legal requirement.

There is another obvious reason that the ALJ's analysis of the constitutional standard from *Willcox* is clearly incorrect. As the Supreme Court stated in *Bluefield*, the question for federal courts in cases involving state ratemaking is "whether the rates prescribed in the commission's order are confiscatory and therefore beyond legislative power." *Id*. at 690. Federal courts have no authority to interpret state ratemaking decisions made pursuant to state law except to the extent that the state's action involves some aspect of federal or U.S. constitutional law. Consistent with that constraint, the Supreme Court held in *Bluefield* that "[r]ates which are not sufficient to yield

a reasonable return on the value of the property used at the time it is being used to render the service are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment." *Id*. In other words, the Supreme Court recognizes that the Fourteenth Amendment of the U.S. Constitution sets a lower limit on the return that a state regulator can use for setting utility rates. Any amount below that limit is "not sufficient," i.e. not high enough, because it would "confiscate" the utility's property without just compensation.[10] However, "confiscation" (and hence a Fourteenth Amendment violation) cannot occur when the state compensates a utility too much for the use of its property. No business would mount a constitutional complaint if the state compensated the business $1 million for taking an asset worth only $100. It wouldn't make sense because the Constitution protects against *insufficient* compensation – not *excess* compensation. Thus, the U.S. Supreme Court has *never* recognized a constitutionally mandated upper limit on the return that a state regulator can use for setting utility rates under the Fourteenth Amendment. However, that is exactly what the ALJ claims the *Willcox* Court has done by claiming that *Willcox* "require[s] that authorized ROEs be set at a level of returns which are less than the expected returns for the general market." PFD, page 529 (emphasis added). That does not make sense in the context of the U.S. Supreme Court's constitutional review of state commission decisions.

The ALJ correctly observed that the U.S. Supreme Court recognized that ratemaking involves a "balancing of the investor and the consumer interests." *Hope*, 320 US at 603. However, the *Hope* Court did not establish that as a constitutional principle establishing some supposed upper limit on returns. In *Hope*, the Supreme Court was *not* reviewing a ratemaking decision by

[10] The U.S. Supreme Court incorporated the Fifth Amendment's protection against government takings of property without just compensation to the states through the due process clause of the Constitution. *Chicago, B & QR Co v City of Chicago*, 166 US 226, 241; 17 S Ct 581; 41 L Ed 979 (1897).

a state regulator. *Hope* involved rates set by a federal agency (the Federal Power Commission) under a federal statute (the Natural Gas Act of 1938). The *Hope* Court was clear that the "balancing" principle was an interpretation of the "just and reasonable" rates requirement of the Natural Gas Act applicable to federal ratemaking – not a constitutional principle applicable to state ratemaking. *Id*. Michigan courts have recognized a parallel "balancing" principle under state statutory law. See, e.g., *City of Detroit v Michigan Pub Serv Comm*, 308 Mich 706, 716; 14 NW2d 784 (1944). But, none of that supports the ALJ's contention that the U.S. Supreme Court would have any lawful basis for establishing a rule that sets an upper limit on all utilities' ROEs nationally as a matter of *constitutional* law. His interpretation of *Willcox* is, once again, clearly erroneous.

If such a legal requirement did exist (which it does not), it would potentially be incompatible with the U.S. Supreme Court's standard that a constitutionally sufficient return must be "equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties." *Bluefield*, 262 US at 692. If other companies with similar risks to Consumers Energy are currently enjoying returns at or above the "returns for the general market" or the "expected returns for the general market" (whichever the ALJ claims it is), the *Bluefield* and *Hope* precedents require Consumers Energy's return to be <u>equal</u> to those returns and, according to the ALJ, the *Willcox* precedent requires Consumers Energy's return to be <u>below</u> those returns. Both cannot simultaneously be true. But, whereas the *Bluefield* and *Hope* standards have been clearly and directly articulated by the U.S. Supreme Court in express language, the ALJ's supposed *Willcox* standard is merely the ALJ's own extrapolation from a Supreme Court case that never said what the ALJ now claims to be law. It defies proper legal reasoning to suppose that the Supreme

Court would have rendered incompatible constitutional mandates on the same topic, particularly when one of those mandates has never expressly been stated.

The problem caused by the ALJ's misreading of the *Willcox* opinion is not merely hypothetical either. In this PFD, the ALJ ultimately concluded that the *Bluefield* and *Hope* standards required "divergent and conflicting" results as compared to the supposed *Willcox* standard. PFD, page 542. The ALJ concluded that "the estimating models suggest that a reasonable ROE commensurate with the returns earned by other regulated utilities," i.e. an ROE consistent with the *Bluefield* and *Hope* standards, "is about 9.7%." PFD, page 542. In contrast, the ALJ concluded that "a reasonable ROE less than the expected return earned by the riskier general market," i.e. an ROE based on his novel *Willcox* reading, "is about 6.7%." PFD, page 542. To resolve this self-made conflict, the ALJ elected to propose an ROE in this case that is simply the mathematical average of 9.7% and 6.7% - i.e. he proposed an ROE of 8.2%. PFD, page 542. According to the ALJ, this approach "best aligns with the conflicting Supreme Court standards" because it is "equally removed from fully complying with the standards." PFD, page 542. But, stating that it is "removed from fully complying with the standards" is a euphemism that is tantamount to saying that it *does not* comply with the standards. And, recall that the standards under discussion here are *constitutional* standards. The PFD *admits* that it *does not* meet the constitutional standards. On this, at least, the Company agrees. In pursuit of a fictitious standard, the PFD fails to meet the *actual* constitutional standard.

The Commission should discard the ALJ's entire line of reasoning based on the novel and illegitimate legal theory that *Willcox* created some heretofore unheard-of standard that prohibits the Commission from approving an ROE that exceeds the "expected returns for the general market." The Supreme Court has never articulated any such standard. The Commission should

disregard the ALJ's introduction of the alternative 6.7% ROE limit entirely and reject the ALJ's approach of averaging that value against the ROE value that he recognized as "commensurate with the returns earned by other regulated utilities" resulting from the quantitative models. That entire part of his analysis is clearly constitutionally wrong. In addition, the ALJ's faulty *Willcox* standard also infected virtually every part of his analysis of the evidence presented by the parties associated with the traditional means of evaluating ROE. As a result, even his assessment that the traditional models support a 9.7% ROE is too low. For the reasons set forth in Consumers Energy's Initial and Reply Brief in this case, and for the further reasons discussed below, the Commission should reject even that analysis and instead approve the Company's recommended ROE of 10.25% in this case. The ROE should at least be set no lower than the Company's most recently established ROE of 9.90% for its electric business.

### 2. The ALJ's Official Notice of Facts and Related Analysis Was Improper and Should Not Be Considered by the Commission

Even if the ALJ's supposed *Willcox* standard were valid (which it is not), the Company would have concerns about the ALJ's analysis of the "expected return of the general market." The 6.7% figure comes from an "Official Notice of Facts" that the ALJ took the liberty of issuing in this case on October 3, 2025. See PFD, page 529. The ALJ's Official Notice of Facts took the 6.7% figure from a January 2025 paper from the American Economic Liberties Project, an advocacy group founded in February 2020 to "help translate the intellectual victories of the anti-monopoly movement into momentum towards concrete, wide-ranging policy changes that begin to address today's crisis of concentrated economic power."[11] The author of the paper indicates that the data came from "investment firm forecast reports" and "author analysis," but does not provide any further detail on the sources of the data other than listing 34 investment firms along

[11] https://www.economicliberties.us/about/; accessed on February 7, 2026.

the bottom axis of a chart.[12] The ALJ offered no explanation in the Official Notice of Facts to support a finding that the 6.7% figure taken from such a source and lacking sufficient detail to confirm all the underlying data constitutes "judicially cognizable facts" or "general, technical, or scientific facts within the commission's specialized knowledge" as required by Rule 428 of the Rules of Practice and Procedure Before the Michigan Public Service Commission, Mich Admin Code R 792.10428. Consumers Energy disputes whether this information is suitable for official notice and, pursuant to Rule 428, disputes the materiality of the information even if the Company granted, for sake of argument, that it is accurate.

As to the propriety of taking official notice of such facts, the Michigan Court of Appeals, in an unpublished opinion, held that "cognizable facts" are facts that are "capable of being perceived and known." *Whispering Pines Golf Club, LLC v Twp of Hamburg*, unpublished opinion of the Court of Appeals, issued August 21, 2007 (Docket No. 269118), page 4 (attached to these Exceptions as Attachment C). The Company submits that "Wall Street asset managers' . . . average expected long term (10+ years) aggregate United States equity market return forecast is 6.7%" is not something that can be simply "perceived." It requires the sophisticated collection and synthesis of data from numerous sources that are not necessarily readily available to the average person. Rule 201(b) of the Michigan Rules of Evidence provides that a "judicially noticed fact" must be a fact "not subject to reasonable dispute" and that is either "(1) generally known within the territorial

[12] See American Economic Liberties Project paper, entitled "Rate of Return Equals Cost of Capital: A Simple, Fair Formula to Stop Investor-Owned Utilities From Overcharging the Public" as linked in the ALJ's Official Notice of Facts at the following web-address: https://www.economicliberties.us/wp-content/uploads/2025/01/20250102-aelp-ror-v5.pdf. Consumers Energy notes that the paper's author, Mark E. Ellis, provided testimony on ROE and capital structure issues in North Carolina in a 2023 Duke Energy Progress LLC electric rate case, which analysis the North Carolina Utilities Commission rejected as "an outlier" that "is clearly insufficient to compensate investors for the added risks associated with equity ownership relative to a debtholder's claim on the same enterprise." NCUC Docket No. E-2, SUB 1300, Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Public Notice, Dated August 18, 2023, page 159. With respect to Mr. Ellis's proposed market risk premium specifically, the North Carolina Utilities Commission concluded that it was "unreasonably low and should be ignored." *Id*. at 162.

jurisdiction of the trial court or (2) capable of accurate and ready determination by resort to sources whose accuracy cannot reasonable be questioned." Consumers Energy submits that there is insufficient information to know whether the facts set forth in the ALJ's Official Notice of Facts is "subject to reasonable dispute." The underlying data on which it is based is not actually identified with any specificity in the sources made available to the parties. Furthermore, the paper in which the data was gathered is an advocacy organization with a clearly stated agenda, not a dispassionate academic source. The data in the American Economic Liberties Project's paper is not "generally known" within the Commission's jurisdiction and the information, at the very least is not "capable of . . . ready determination by resort to sources whose accuracy cannot reasonably be questioned." Finally, the data do not appear to be "general, technical, or scientific facts within the commission's specialized knowledge" as required by Rule 428. The Commission's specialized knowledge pertains to the public utility industry, not to market return forecasts for businesses in far-ranging industries beyond the utility industry.

As to the materiality of the data, the information in the ALJ's Official Notice of Facts is only material if his claim regarding the supposed legal standard from *Willcox* is valid, but it is not. The Supreme Court has never adopted any legal standard that requires the Commission to compare a utility's ratemaking ROE to the returns in the general market. In fact, the Supreme Court's actual standard requires the Commission to base its ROE determination only on businesses that have been shown to have "corresponding risks" to the utility. The ALJ's Official Notice of Facts violates that principle. There are undoubtedly businesses in the "general market" that have greater risk than Consumers Energy and businesses that have less risk than Consumers Energy. That's why ROE witnesses perform analyses of quantitative models based on proxy groups of utilities that are similar to Consumers Energy.

Even if it were appropriate to consider information regarding the "general market" (which it is not), the ALJ has not provided any reason to believe that the American Economic Liberties Project's average expected long term aggregate United States equity market return forecast represents the correct data point to represent the "general market." Company witness Ann E. Bulkley testified that "studies have shown that investment firms have not accurately forecasted actual returns." 4 TR 2801. As an example, she explained that "the investment firm Dimensional Fund Advisors LP compared the return forecasts of investment firms published in the capital market assumption reports (*i.e.,* the same reports used to calculate the 6.7% market return referenced by the ALJ) for various asset classes for the ten-year period of 2014-2023 to the returns that were achieved over the same time-period." 4 TR 2801. Dimension Fund Advisors LP found that the investment firm forecasts did not prove to be accurate. According to Ms. Bulkley, the comparison showed that "forecasted returns from investment firms for U.S. equities ranged from 5.5% to 7.7% for the period of 2014-2023; however, the actual return for U.S. equities over this period was 11.50%, or substantially greater than the range projected by the various investment firms." 4 TR 2801. It is possible to compare Dimensional Fund Advisors LP's results to other data in the record, which also supports the conclusion that historical 10-year market returns are significantly higher than the forecasts from those investment firms. Staff witness Kirk D. Megginson sponsored Exhibit S-4, Schedule D-5, page 6, which shows "Large Company Total Market Returns" dating back to 1928. Using the same 2014-2023 time period as Dimensional Fund Advisors LP used, Mr. Megginson's exhibit yields a return of 12.98% during that ten-year time horizon, also far higher than the 5.5% to 7.7% range predicted by investment firms. Ms. Bulkley performed her own forecast of expected market returns over the next 10 years and

concluded that, based on data from the time of her direct testimony, the expected market return was 12.58% and more recent data indicated 13.34%. 4 TR 2800-2801.

For the reasons discussed above, the ALJ's Official Notice of Facts was improper, as was the ALJ's analysis regarding the existence and significance of an "expected general market" return of 6.7%. In addition to being based on a non-existent legal standard, the data itself is questionable and the ALJ did not meet any of the legal criteria for introducing the data as an officially noticed fact. The Commission should not consider it in any respect as part of making its ROE determination in this rate case.

### 3. The ALJ's Analysis of the ROE Evidence is Not Reasonable and Would Improperly Understate the Company's Required ROE

Setting aside the ALJ's improper analysis regarding supposed *Willcox* standard, the return for the "general market," and his invalid attempt to incorporate that analysis into his final recommendation, the ALJ otherwise concluded that "the results of the estimating models suggest that a reasonable ROE commensurate with the returns earned by other regulated utilities is about 9.7%." PFD, page 542. The ALJ arrived at this recommendation by averaging the average results from the quantitative models that he chose to accept from the various ROE witnesses in the case. PFD, pages 518-519. The ALJ chose not to consider the results from some of the Company's quantitative analyses, so those results were not included in the ALJ's calculation of the 9.7%. However, the ALJ's reasoning for rejecting certain of the Company's ROE model results is not valid. The Commission should consider all of the Company's quantitative ROE estimates, which support an ROE in this case higher than the 9.7% calculated by the ALJ.

#### a. Capital Asset Pricing Model

The ALJ did not consider Consumers Energy's Capital Asset Pricing Model ("CAPM") results. PFD, page 511. He claimed that the Company's CAPM analysis was "unreliable" because

"Ms. Bulkley's calculation of its projected market return apparently included some companies that are not paying dividends." PFD, page 511. However, that claim fails to understand the nature of the analysis and is, as a result, incorrect. The ALJ also criticized Ms. Bulkley's rebuttal testimony in which she cited a 2015 analysis (hereafter "the 2015 Fed Report") from the Federal Reserve Bank of New York (hereafter "the New York Fed") as an example of a study that demonstrates the reasonableness of her projected equity risk premium. The ALJ claimed that Ms. Bulkley's risk premiums were "well above the averages calculated by the Federal Reserve report she cites." PFD, page 511. That claim is also not correct. Neither of these claims is a valid reason for refusing to consider the results of Ms. Bulkley's CAPM analysis.

With respect to the ALJ's first reason, he fails to understand that the analysis is meant to derive a projected risk premium for the market as a whole by performing a Discounted Cash Flow ("DCF") analysis using aggregate market data instead of data for an individual company. The ALJ is correct that the DCF requires dividend data. When applied to an individual company, that means the Company must be one that pays dividends or the analysis would be fruitless. But, when considering the market as a whole, the DCF can use data about the dividends that the market in the aggregate is paying, even if some companies in the market do not pay dividends. Contrary to the ALJ's claim, it is only possible to derive that data from those companies in the market that are paying dividends. Ms. Bulkley's projected market return only included companies in the calculation of the "Estimate of the S&P 500 Dividend Yield" if the individual company had dividend yields (and not even all of those). In order to be included in the calculation, an S&P 500 company had to have a value for dividend yield and long-term growth estimate between 0% and 20%. See Exhibits A-14 (AEB-1), Schedule D-5, page 16 and A-206 (AEB-2), page 15. In order to confirm that, the ALJ only needed to look at the native Excel version of the exhibits to see how

cell C4 and the values in column [8] of Exhibit A-14 (AEB-1), Schedule D-5, page 16 and cell C3 and the values in column [8] of Exhibit A-206 (AEB-2), page 15 were calculated. No party made the claim that the ALJ made about the use of companies without dividends for that calculation. Therefore, the ALJ should not have made any assumptions about what was happening on that exhibit without at least checking the formulas. Ms. Bulkley derived a dividend yield for the whole S&P 500 which was based on companies within the S&P 500 that pay dividends and then used the dividend yield for the whole S&P 500 to calculate an estimated market return for the whole S&P 500. The ALJ's first reason for not considering the Company's CAPM results is invalid.

There is also no merit to the ALJ's claim regarding the 2015 Fed Report. First, the ALJ cites the 2015 Fed Report's conclusion that the one-year-ahead risk premium in June 2012 was 12.2% and its observation that the risk premium was likely high because Treasury yields at that time were "unusually low."[13] The ALJ never explicitly explains how these points undermine Ms. Bulkley's projected risk premiums of between 8.55% and 8.94%. It appears that the ALJ means to suggest that the 12.2% risk premium found in the 2015 Fed Report may be an extreme outlier caused by conditions not currently holding true. If Ms. Bulkley were promoting a risk premium of 12.2% in this case without showing a similarly low Treasury yield, that *might* have some intellectual weight. But, interest rates have risen since 2012 (see, e.g., 4 TR 2805, though

[13] The ALJ acknowledges that the 2015 Fed Report was not offered as an exhibit in this case. See PFD, page 510, note 5331. The ALJ used an exhibit from another case (Case No. U-21389) in order to perform his own detailed review of the 2015 Fed Report. The ALJ cited this language from that exhibit. The Administrative Procedures Act of 1969 provides that "[e]vidence in a contested case, including records and documents in possession of an agency of which it desires to avail itself, shall be offered and made a part of the record." MCL 24.276. The statute further states that "[o]ther factual information or evidence **shall not be considered** in determination of the case, except as permitted under section 77 [pertaining to official notice of facts]." *Id*. It was improper for the ALJ to seek out and use non-record evidence as part of his recommendation in this case. To the extent that the ALJ thought that the full report was needed, this might have been a proper circumstance for using the authority to take official notice (unlike his use of judicial notice discussed above). However, having failed to do so, he should not have relied upon any non-record portions of the 2015 Fed Report. Because the ALJ chose to do so contrary to the law, basic notions of fairness and due process require that Consumers Energy also be permitted to refer to that exhibit in response. However, the most correct resolution of this legal problem would be for the Commission to simply disregard all of the ALJ's arguments from that non-record document.

they are still below the historical average interest rate of those same bonds (see 4 TR 2851) and Ms. Bulkley's proposed risk premiums have moderated accordingly. Ms. Bulkley testified repeatedly that there is an extensive body of "academic literature and market evidence indicating 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)." 4 TR 2749. That was one of the main criticisms Ms. Bulkley had of some of the other parties' approaches to estimating an equity risk premium because they made no effort to ensure that their risk premiums corresponded inversely to the expected level of interest rates. So, the information the ALJ cited from the 2015 Fed Report supports, rather than undermines, Ms. Bulkley's analysis.

The ALJ also quoted the report as stating that there remains "considerable uncertainty around these estimates" and that it is still an "active area of research." That may be true, but the New York Fed certainly concluded that its study added *something* to the prevailing understanding of how well equity risk premium models estimate risk premiums or it wouldn't have published it. Those are just the ordinary caveats and cautions commonly included in all economic research where the models cannot provide 100% confidence of results because they cannot conclusively establish a closed-system cause-and-effect relationship.[14]

Finally, the ALJ claimed that one singular piece of data from the 2015 Fed Report conclusively "shows that Consumers[ Energy]'[s] market risk premium is excessive." PFD, page 511. The ALJ claimed that "the Report states that the average equity risk premium for all of the models as well as the historical average equity risk premium for the five years prior to the study

[14] These same types of caveats and cautions not to rely on estimates would be included, for example, in the expected return forecasts for the general market prepared by the investment firms that were cited in the American Economic Liberties Project's Report used by the ALJ as support for his Official Notice of Facts. If these caveats categorically render this information unusable for analysis, then the same categorical problem exists with the ALJ's Official Notice of Facts.

period were both 5.7%." PFD, page 511. There are several problems with that claim. First, it is factually inaccurate. Table VII of the 2015 Fed Report does include a value of 5.7%, which represents the mean value of all models reviewed. See Exhibit A-172 (TAW-10), page 31 from Case No. U-21389. However, that was not the average "for the five years prior to the study period." That was the average from the results of all 20 models over the period from January 1960 to June 2013, a period of 53 years. See A-172 (TAW-10), page 26, Table I (Note) from Case No. U-21389. Second, the ALJ completely fails to understand the purpose of calculating that value in the 2015 Fed Report. When understood, it is clear that the value does not support his claim. The New York Fed placed no independent significance on the 5.7% value in its own analysis. The New York Fed was more concerned with calculating a "first principal component," which was a composite value that represented the results for each year for a one-year forward period for all 20 models. The only use that the New York Fed had for the 5.7% mean of all 20 models for the entire 53-year period was that it was one of the inputs used to calculate the "first principal component." The New York Fed explained that the "first principal component" was calculated by de-meaning all the equity risk premium estimates for all 20 models over all 53 years, then finding the linear regression of the de-meaned data, and then adding the 5.7% mean to the results. See Exhibit A-172 (TAW-10), page 13 from Case No. U-21389. In that calculation, the New York Fed regarded the 5.7% value as "an unbiased and consistent estimator of the unconditional mean of the ERP." Exhibit A-172 (TAW-10), page 13 from Case No. U-21389. In other words, due to the effect of averaging out all of the models over such a long time-horizon, the 5.7% value could fairly represent what the equity risk premium would look like in the absence of the myriad independent conditions that make it rise of fall under particular real-world circumstances. But, real-world equity risk premiums never exist in a vacuum. They are always being acted on by economic circumstances

at the time. The de-meaned linear regression represented the impact of those circumstances isolated from the unconditional mean of the equity risk premium. So, to determine what an expected risk premium would be, it was necessary to add both the 5.7% value and the linear regression value representing the composite impact of the circumstances measured by the 20 models at a given time. Because the process is additive to the 5.7%, the 5.7% taken alone will always misrepresent the expected equity risk premium predicted by the composite of the 20 different models. But, that's what the ALJ did. The New York Fed graphed the "first principal component" data in Figure 2 of the 2015 Fed Report. See Exhibit A-172 (TAW-10), page 33. As Figure 2 shows, from around the year 2000 through the end of the data in 2013, the composite equity risk premium from all 20 models has been consistently above the 5.7% and appears to have remained generally above 7.5%, exceeding 10% in the last three years of the data. Ms. Bulkley was right that the 2015 Fed Report provides an example to support the reasonableness of her forecasted equity risk premiums.

There was no valid basis for the ALJ to disregard Ms. Bulkley's CAPM analyses. The Commission should reject the ALJ's approach and consider the Company's CAPM results in setting the ROE in this case.

**b. <u>Empirical CAPM ("ECAPM")</u>**

The ALJ declined to consider the results of the Company's ECAPM model because the Company "has not identified an order whereby the Commission has previously recognized the use of the ECAPM model." PFD, page 512. He argues that the Commission has consistently taken a "traditional approach" to establishing ROE and relying on the "most commonly-used fundamental approaches." PFD, page 512. That is not a valid reason to disregard the Company's ECAPM.

Parties in Michigan rate cases (including Consumers Energy, DTE Electric Company, DTE Gas Company, Indiana Michigan Power Company, and Wisconsin Electric Power Company) have used ECAPM as part of ROE presentations for more than 20 years. Although the Commission has not issued an order expressly endorsing ECAPM, the Commission has also never issued an order indicating that it does not recognize or consider ECAPM. In fact, in Case No. U-16472 (a Detroit Edison Company electric rate case), the Commission clearly did implicitly consider ECAPM because one of the reasons that the Commission cited for rejecting Detroit Edison Company's proposed ROE of 11.125% in that case was because Staff pointed out that the recommendation exceeded the average estimate of Detroit Edison Company's CAPM and ECAPM results. October 20, 2011 Order, page 38.

The ALJ emphasizes that the Federal Energy Regulatory Commission ("FERC") has declines to use ECAPM. PFD, page 512. However, the Commission is not bound to follow FERC's decisions, which are persuasive at most. While FERC may have chosen not to use ECAPM, other regulatory commissions have recognized and used it. 4 TR 2882-2883. Furthermore, there is academic research that supports the theoretical basis for and use of the model. 4 TR 2877-2879. Contrary to the ALJ's implicit claim, ECAPM is one of the "traditional approach[es]" to establishing ROE and is "commonly used" for that purpose. In the Company's experience, the Commission does not typically state explicit support for the particular methodologies that informed or persuaded its final ROE authorizations. Instead, the Commission's history of rate orders suggests that the Commission generally weighs all of the evidence presented in support of the various ROE recommendations. The PFD offers no good reason to depart from that practice.

### c. Discounted Cash Flow Model

The ALJ concluded that one of the inputs into the Company's DCF Model analysis was inappropriate and therefore indicated that he would only consider an adjusted version of it. PFD, page 513. The ALJ agreed with Staff's claim that some of the growth rates for Dominion Resources Company ("Dominion") used in Consumers Energy's DCF were "outliers" and that the Company's DCF should be adjusted to exclude Dominion from the analysis. However, the ALJ did not address the Company's response to Staff's argument, which shows that the higher growth rates for Dominion were not outliers.

First, to be clear, Dominion met all of the criteria for inclusion in the Company's proxy group in this case, and the ALJ has not argued that Dominion should be removed from any of the Company's other quantitative models. It is an appropriate proxy for Consumers Energy. The ALJ apparently only seeks to remove Dominion from the DCF model because the Dominion inputs needed for this model are higher than those of the other proxy companies. But, that is not a legitimate reason for exclusion. To perform her DCF analysis, Ms. Bulkley obtained three growth estimates for each proxy company from three different sources.[15] Of the three growth estimates that Consumers Energy obtained for Dominion, the *low* estimate is the outlier – not the two *high* estimates. The growth estimates from *S&P Capital IQ* and *Zacks* are consistent with one another in both the Company's original DCF calculations (See Exhibit A-14 (AEB-1), Schedule D-5, pages 3-5) and its updated DCF calculations (See Exhibit A-206 (AEB-2), pages 24). If anything, the use of all three is artificially *reducing* the mean results of Ms. Bulkley's analyses compared to running the same analysis without the low-end *Value Line* growth estimate.

[15] Ms. Bulkley's analysis also included median and mean results. Medians address the effects of outliers. The ALJ either ignored or failed to understand this.

Second, while the *S&P Capital IQ* and *Zacks* growth rates of around 13% for Dominion remained relatively consistent when Ms. Bulkley updated them in her rebuttal, *Value Line*'s growth rate had nearly doubled by the time of Ms. Bulkley's update from 3.5% to 6.0%. See, e.g., Exhibit A-206 (AEB-2), page 2, column [5]. Clearly, in the time between the Company's direct testimony and its rebuttal testimony, even *Value Line* recognized that Dominion is expected to experience stronger growth than *Value Line* originally estimated. This suggests that there is probably some sound basis for *S&P Capital IQ*'s and *Zacks*' stronger growth estimates in the first place. It is also noteworthy that *S&P Capital IQ*'s and *Zacks*' earnings per share ("EPS") growth forecasts are based on consensus estimates from multiple sources. 4 TR 2837. *Value Line*'s forecast is not.

Third, the ALJ fails to acknowledge that, for each of her three DCF analyses, Ms. Bulkley performed a model run using the minimum growth rate, the maximum growth rate, and the mean growth rate from the three sources. See Exhibits A-14 (AEB-1), Schedule D-5, pages 3-5 and A-206 (AEB-2), pages 2-4. So, eliminating Dominion's three growth rate projections from the data set entirely could *increase* the results of Ms. Bulkley's minimum growth rate model run. For example, removing Dominion from Ms. Bulkley's original 180-Day Constant Growth DCF would increase the mean ROE result from 9.16% to 9.19% and the median ROE result from 9.79% to 9.81%.[16] This demonstrates that Dominion does not – as a general proposition – lead to higher results in all the Company's DCF analyses just because it has a higher estimated growth rate.

This issue highlights the importance of using objective criteria in the selection of the proxy group and not arbitrarily excluding any of the inputs for the proxy companies while running the

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

models merely based on some subjective perception that the inputs appear to be outliers. The use of a large group of proxy companies, multiple different sources of growth forecasts for each, and numerous variations of the DCF model runs, including the calculation of both mean and median results, produces results that give a fuller picture of a true market-based ROE estimate. It tends to moderate and control for outliers, while still incorporating appropriate consideration of all the comparable companies in a scientific manner that is not driven by a predetermined conception of the desired outcome. In contrast, the ALJ's recommendation is subjective and outcome-driven. The ALJ's exclusion of Dominion from the Company's DCF is not sound and it must be rejected.

The ALJ also claimed that the Company's and Staff's short-term three-year growth rates under a single-stage DCF were misleading because "a short-term growth rate cannot exceed the anticipated growth rate for the economy as a whole." PFD, page 514. He concluded that those results should be attributed less weight because they are high-end estimates. PFD, page 514. The ALJ again did not address the Company's response to the other parties on that issue. Contrary to the ALJ's assertion, Ms. Bulkley points to studies showing that the theory that utility growth cannot exceed GDP growth is invalid. Specifically, Ms. Bulkley cites a study filed as part of the Rate Regulation Initiative of the Alberta Utilities Commission in which the authors calculated total factor productivity ("TFP") growth for 72 U.S. electric and combination electric and natural gas utilities and for the U.S. economy for the period of 1972 through 2009. 4 TR 2843. Ms. Bulkley testified: "For the U.S. utility group, TFP growth averaged 0.96% over the period of 1972 to 2009, while TFP growth for the U.S. economy was 0.91%, indicating that electric and combination electric and natural gas utilities were approximately 5.00% more productive than the U.S. economy over the study period." 4 TR 2843. Therefore, contrary to the ALJ's claims, the authors

demonstrated that utility growth can exceed growth for the U.S. economy and actually did so for a period of approximately 40 years.

Finally, the ALJ improperly dismissed Ms. Bulkley's criticism of ABATE witness Christopher C. Walters' multi-stage DCF and MNSC witness Matthew Bandyk's two-step DCF because Ms. Bulkley testified that their DCF results were "well below the low-end of the range of comparable authorized returns for electric utilities in at least the last 45 years," which the ALJ claimed was "contradicted by evidence submitted in two recent Commission cases . . . ." PFD, page 515. Setting aside the issue that the ALJ once again relied on non-record evidence in violation of the Administrative Procedures Act of 1969 in making his recommendation, the information the ALJ pulled from prior rate cases does not refute Mr. Bulkley's testimony. Again, Ms. Bulkley's point was that the results from Mr. Walters' and Mr. Bandyk's models were well below the low end of the range of "comparable authorized returns for electric utilities." The ALJ fails once again to correctly understand the constitutional standard from *Bluefield* and *Hope* applicable to setting the return in rate cases, which requires the Commission to set Consumers Energy's return consistent with the returns of other businesses having corresponding (i.e. comparable) risks. The Company does not dispute the ALJ's observation that there were seven total utilities[17] in the United States in the three-year period of 2021, 2022, and 2023 that received lower ratemaking ROEs than suggested by the results of Mr. Walters' and Mr. Bandyk's DCF analyses. But, the ALJ made no effort to show that the seven utilities receiving the lowest ROEs in three recent years are "comparable" to Consumers Energy. Those seven utilities represent just 0.2% of all the electric utilities in the country. Ms. Bulkley's testimony referred to Mr. Walters' and Mr. Bandyk's analyses producing results that were lower than any other comparable electric utility in at least

[17] For context, there are around 3,000 electric utilities in the United States.

45 years, and the ALJ's non-record evidence does not contradict that expert testimony. It is troubling that the ALJ concluded Mr. Walters' and Mr. Bandyk's DCF results, which would benchmark Consumers Energy's ROE to the lowest seven utilities nationally, are "reasonable" and should be given greater weight than the ROE analyses produced by Staff and the Company.

**d. National Approved Regulatory ROE Data and Trend**

Because the ROE witnesses for other parties routinely refer to reports showing approved ratemaking ROE nationally as part of their analysis, and because investors consider them, Ms. Bulkley also reviewed the data as part of her testimony. The Commission has previously stated that it will consider approved ROEs from other states, but does not give significant weight to them, particularly when they involve proceedings exclusively related to geographically and structurally different utilities. MPSC Case No. U-17895, September 8, 2016 Order, page 20. That is the appropriate approach consistent with the requirements of *Bluefield* and *Hope*, which requires the Commission to set Consumers Energy's return consistent with the returns of other businesses having corresponding risks. Consumers Energy has expressed concerns about the unfiltered over-reliance on the outcomes of approved ROEs nationally in numerous past cases for that very reason and continues to encourage caution in how that data is used and how much weight is accorded to it. However, one area where an analysis of approved ROEs nationally can be very meaningful in a rate case is to monitor any trends occurring in the data. Accordingly, Ms. Bulkley offered some critique of the other parties' analyses for failing to apply any filters to their analysis to try to limit the scope of the data to utilities with some corresponding similarities to Consumers Energy, which should at least distinguish between vertically integrated utilities and those that own only distribution assets and her own analysis focused on the current trend. 4 TR 2802-2805.

The ALJ makes several errors in his analysis of the various parties' positions on the use of approved ROEs nationally for recent years. First, he criticizes Ms. Bulkley for not identifying the utilities that she believes should be excluded from the analysis using her filters. PFD, page 521. But, there was no reason for her to list those utilities because she excluded them from her own analysis. The ALJ didn't need to calculate the results based on the remaining group because Ms. Bulkley already performed that calculation and provided the results in her testimony. 4 TR 2804.

Next, the ALJ criticized the fact that Ms. Bulkley included approved ROE data for 2021 and 2022 in her analysis even though she advised that Staff's analysis was flawed by including data from those same years. The ALJ claimed that Ms. Bulkley contradicted her own criticism of Staff's analysis. PFD, page 521. But, the ALJ failed to understand that there is a material difference between Staff's analysis and Ms. Bulkley's. Ms. Bulkley simply presented the statistics for each of the five years in her review period as stand-alone information by year. Staff, in contrast, calculated a four-year average ROE value across the entire time period of his review. Ms. Bulkley did not critique Staff's inclusion of the data from those years individually. Taken individually, it is easy enough for an analyst to simply assign different significance to each year's data consistent with how Treasury yields were different in those years. But, when those results are averaged with other years with different prevailing interest rates, the resulting average is misleading.

Third, the ALJ accused Ms. Bulkley of using inconsistent methodologies for her risk premium analysis in direct testimony and her national ROE trend analysis in her rebuttal testimony because, he claims, she used a different data source. PFD, page 521. The ALJ asserts that Ms. Bulkley used S&P Capital IQ in one analysis and Regulatory Research Associates ("RRA") in the other. That claim is also based on the ALJ's misunderstanding. RRA and S&P Capital IQ

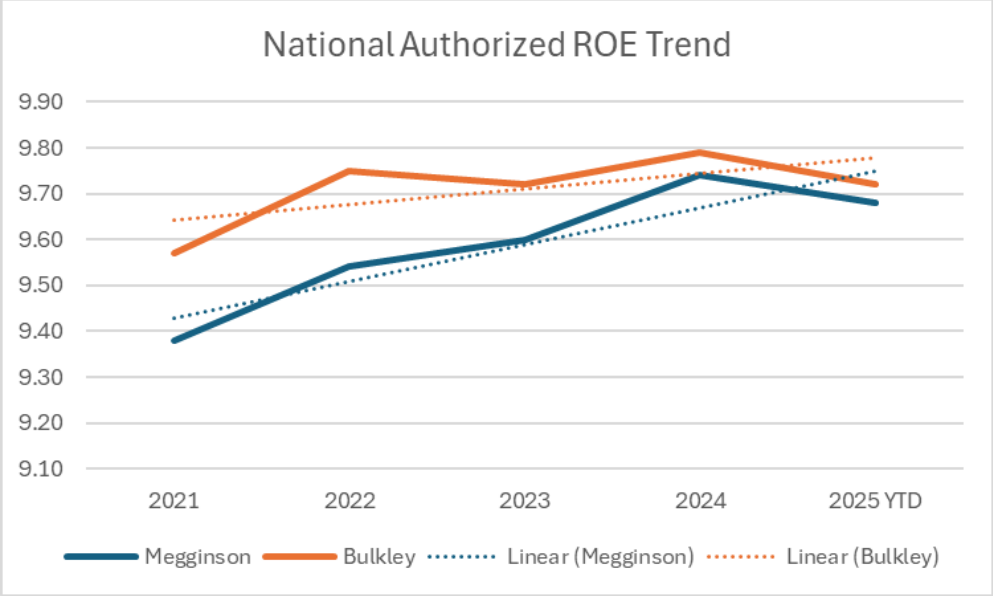
are the same source. RRA is the regulatory database published by S&P Capital IQ that contains the approved ROE data. The ALJ also accused Ms. Bulkley of using different screening criteria between the two analyses. PFD, page 521. However, the only difference was that she did not include penalties back to 1980 as a screen in her risk premium analysis, which was unnecessary because it is reasonable to assume that with the number of data points in the regression, the penalties will not skew the results of that analysis. As shown in the risk premium exhibit, Exhibit A-14 (AEB-1), Schedule D-5, pages 23-25, the regression is relying on 181 observations, which are quarterly averages of authorized ROEs back to 1980, so any individual penalty factored into these averages is not likely to affect the outcome of the regression.

Finally, the ALJ disputed Ms. Bulkley's testimony that "authorized ROEs have increased" over the last five years. PFD, page 522. Instead, the ALJ found that "the average of recently authorized ROEs from other states is between 9.50% – 9.60% and [is] trending lower." This, again, is demonstrably incorrect. Only two witnesses in this case presented multiple years of RRA data on approved ROEs nationally: Ms. Bulkley and Staff witness Megginson. The table below shows the data presented by each witness (see 4 TR 2804 (Bulkley); 6 TR 4548 (Megginson)):

| Witness | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|
| Megginson | 9.38% | 9.54% | 9.60% | 9.74% | 9.68% |
| Bulkley | 9.57% | 9.75% | 9.72% | 9.79% | 9.72% |

The Company has already explained why it is misleading and inappropriate to average this data, which includes years with very different interest rates, across the entire time horizon as the ALJ has proposed. But, even if it were appropriate to perform such an average, the average is not between 9.50% and 9.60% as the ALJ represents. Staff's data (without appropriate screens for dissimilar utilities) averages approximately 9.6% and the Company's data (with better but still

imperfect screens) averages approximately 9.7%. More importantly, when the data is graphed with a trendline, the trend is clearly increasing – not lower as the ALJ claimed. See graph below:




The data supports Ms. Bulkley's testimony.

On this point, it is critical to understand why the trend of this data is so much more important for analysis in setting ROEs than the actual year-over-year averages. Even with the screens used by Ms. Bulkley, many of the companies included in this list are not sufficiently comparable to Consumers Energy to warrant direct comparison like the proxy group used to perform the quantitative ROE models. But, utilities compete with one another, and with other non-utility businesses, to attract capital in the capital markets. Investors are aware of the ROEs that other utilities are getting in rate cases. But, more importantly, they are aware when some jurisdictions are trending higher in their ROE decisions and other jurisdictions are trending lower. Utility investments tend to be long-term investments. If an investor recognizes that approved ratemaking ROEs are somewhat lower today in one state, but trending up, the investor will often prefer to put long-term investments there instead of in a state where ROEs are somewhat higher today, but trending down. To the investor, the differing trends indicate that the investment will

likely achieve higher overall returns over the long-term in the former state than in the latter. Furthermore, investors experience a level of uncertainty about jurisdictions that are trending down because it can be difficult for them to tell where the bottom of the downward trend is going to be. Investors don't worry about where the top of an upward trend may be. So, in terms of attracting capital, the worst place a utility can be is trending down for ratemaking ROEs while everyone else is trending up. In Michigan, where ROEs have been slightly above other states in recent years, investors are more likely to remain interested in bringing their capital to this state if ROEs are at least stable. So, even if the Commission is not persuaded to increase the Company's ROE at this time, it should certainly not decrease it with so many important capital needs coming up over the next several years to improve distribution reliability and meet the ambitious requirements of the new renewable energy and clean energy standards. An 8.2% ROE result in this case, like the one the ALJ recommended, would be catastrophic for investor perceptions of the long-term investment in Michigan. The Commission should instead adopt the Company's proposed 10.25% ROE or any reasonably appropriate ROE at 9.90% or higher to send a clear signal to investors that there is no need to take their investment dollars elsewhere.

#### 4. ROE Conclusion

It is imperative that the Commission reject the ALJ's recommendation to use an 8.2% ROE in this case, which was based on a non-existent legal standard and faulty and at times unlawful analysis of the evidence. Such a ratemaking ROE would do substantial harm to the Company's ability to attract capital and maintain its credit in direct contradiction to the principles in *Bluefield* and *Hope*. The Commission should set an ROE of 10.25% in this case, but even if the Commission is not persuaded to adopt the Company's ROE, it should set an ROE of at least 9.9% or higher to assure the investment community that Michigan remains a stable regulatory environment.

## IV. ADJUSTED NET OPERATING INCOME

### A. Jurisdictional Revenues and Sales Forecast

In its Initial Brief, the Company supported its test year sales forecast of 33.919 GWh and its test year electric jurisdictional operating revenues of $5.019 billion. In its original Reply Brief, the Company further supported its sales forecast in response to Staff's arguments in its Initial Brief, but after the Company's motion to exceed the page limit was denied, it made the difficult decision to remove this section to meet the ALJ's page limit. The ALJ then adopted Staff's proposed adjustments to the Company's sales forecast.

The ALJ's adjustments to the sales forecast epitomize the flaw in the ALJ's ruling on the Company's motion to exceed the page limit, which deprived the ALJ of information pertinent to the very findings he would later reach. The ALJ, after noting that the Company "provide[d] no further argument on these issues [i.e., the Company's regression model, Staff's model, and their experts' opinions] in its reply brief," decided the issue on the very grounds the Company originally disputed. Compare December 23, 2025 Reply Brief, pages 35-36, with PFD, pages 565-566.

If the ALJ had considered the information in the Company's original Reply Brief about the sales forecast, he would have been forced to grapple with arguments that directly contradicted his findings. Fortunately, the Commission can now rectify this error and consider all the evidence and arguments that show the Company's sales forecast is sound and requires no adjustments.

The ALJ's adjustments to the sales forecast carried forward to the jurisdictional operating revenues, compounding the ALJ's error. *Id.* at 567. The Commission should reject the ALJ's adjustments to the jurisdictional revenues for the same reasons.

#### 1. Sales Forecast

Company witness Eugène M.J.A. Breuring described, in detail, the method he used to project jurisdictional electric deliveries and generation requirements for the test year. 3 TR 937-

942. Key variables affecting the Company's forecasts were weather, the economy, demographics, and line loss (in the case of total generation requirements). 3 TR 942. 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. 3 TR 941. He used S&P Global's (formerly, IHS Markit) employment, industrial, and population forecasts to project economic and demographic changes in his forecast. 3 TR 942. He included full-service and retail choice customers in the forecast. Exhibit A-15 (EMB-2), Schedule E-1. His forecast also reflected the Company's Dynamic Peak Pricing ("DPP") programs, Energy Waste Reduction ("EWR") programs, Conservation Voltage Reduction ("CVR"), and Residential Summer On-Peak ("RSP") rate, 3 TR 939, as shown here:

- Reductions to the peak demand forecast fluctuated between approximately 34 MW in 2025 and 40 MW in 2029 to account for the Company's DPP programs (i.e., its Peak Time Rewards and CPP programs).
- Mr. Breuring further reduced peak demand by 869 MW for EWR and 62 MW for CVR measures in 2025, with a higher cumulative reduction in the test year.
- Finally, Mr. Breuring reduced peak demand by approximately 66 MW for Rate RSP in the test year. 3 TR 953.

Staff recommended a large adjustment to the Company's test year projected deliveries for commercial customers (a 204,656 MWh increase for bundled customers and 16.308 MWh increase for choice customers), which represented a 1.8% increase to commercial load in the projected test year. 3 TR 956; 6 TR 4271, 4281. Staff witness Paul R. Ausum recommended the adjustment based on alterations to the regression models the Company used to forecast electricity demand. 6 TR 4272. Two primary factors drove Staff's higher commercial load forecast: (1) Staff omitted what it described as "unnecessary binary variables" and substituted "non-manufacturing employment from the Company's list of economic indicators as an explanatory economic variable, instead of the Company's service employment variable;" and (2) Staff included an intercept term,

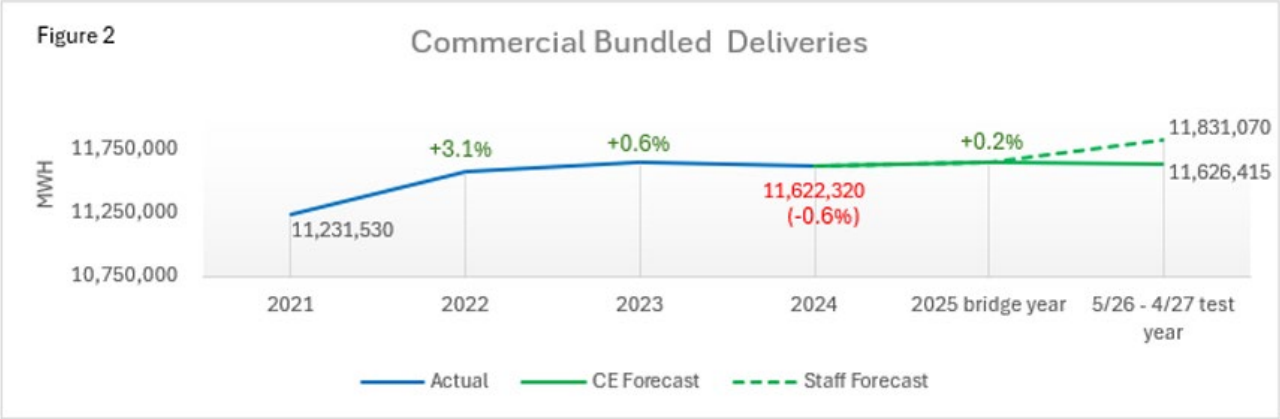
or constant variable, within the regression equation. 6 TR 4278-4279. The ALJ agreed with Staff's higher forecast.

The Company respectfully disagrees with Staff's proposed commercial load forecast, as adopted by the ALJ, for several reasons. The forecast underrepresented historical trends, over relied on the regression model, and incorporated a statistically weak constant variable in its regression model. 3 TR 957.

**a. Response to Staff's Proposed Commercial Load Forecast**

The Company's first concern with Staff's forecast, as adopted by the ALJ, is that it is out of sync with recent historical trends. To unpack this concern, 2020 is a good starting point. Since 2020, the commercial bundled class has been recovering from the impacts of the COVID-19 pandemic. Electric consumption rebounded by 3.1% in 2022 and began to stabilize in 2023, with a modest increase of 0.6%, before declining slightly by 0.3% in 2024. EWR initiatives, which reduce deliveries by approximately 1.8% annually, helped stabilize the trend. 3 TR 957-958. EWR's downward pressure has been partially offset by some growth factors (e.g., EV growth), but these factors do not entirely counterbalance the sustained EWR savings. 3 TR 958.

Despite the historical trend, Staff projected a 1.0% annual growth rate in commercial bundled deliveries by the test year, which is a "significant departure from recent historical delivery trends." 3 TR 959. Mr. Breuring prepared a graph that clearly shows how Staff's projection deviates from the historical trend:




3 TR 959.

As for EV growth, it is already incorporated into the Company's test year forecast. To account for the difference between the Company and Staff's commercial load forecast, EV growth in the Company's model would need to be understated by as much as 24%, or 152,000 vehicles, which is highly improbable. *Id.* Economic growth also cannot explain how Staff's forecast deviates from historical trends. The Company's regression model relied on key economic indicators from S&P Global to account for economic growth, and S&P Global is a reputable source of industry-specific forecasting data. *Id.*

Another flaw in Staff's forecast is its overreliance on the regression modeling. There are times when a model's results must be adjusted based on the forecaster's expert judgment. Mr. Breuring aptly observed that a "forecaster's experience, viewed through the lens of their expertise, can be very helpful in spotting certain trends, especially in the more recent history." 3 TR 960. Experts in the field agree. See 3 TR 961 (citing a study on human judgement and quantitative forecasting methods). "Electric load forecasting requires both analytical precision (using regression models) and adaptive insight (based on the forecaster's experience)." 3 TR 961. Staff's forecast relies almost entirely on its regression model output. 3 TR 962. Although Staff used the Company's adjustment – as an absolute value without refining it – this was a problem

because the differences between Staff's and the Company's models required different adjustments. *Id.*

The Company applied a manual adjustment in combination with its regression model results and recent historical trends, ensuring the adjustment aligned with expected test-year growth in the commercial customer class. By contrast, Staff applied the same adjustment—using the identical absolute value—which was not appropriate for its modeling framework or consistent with projected test-year deliveries. As Mr. Breuring explained, incorporating this adjustment into Staff's forecasting approach produces a test-year delivery projection that cannot be supported by EV adoption trends, economic indicators, or any other plausible growth drivers. This is why the Company's adjustment should not be applied to Staff's model as is. The Company's hybrid approach uses an adjustment specifically calibrated to its modeling and test-year assumptions, whereas Staff applied an adjustment it neither developed nor validated.

The Company's final concern with Staff's forecast relates to a variable that Staff introduced into the model. As noted above, Staff substituted a non-manufacturing employment variable for the Company's service employment variable and Staff included an intercept term, or constant variable, within the regression equation. Staff's first change was not concerning and did not materially affect Staff's final delivery forecast, but Staff's second change was quite concerning. Variables used in a regression model can be statistically tested for accuracy using a "t-statistic," or "t-stat," and "p-value," and Staff's constant variable did not test well. Mr. Breuring explained that "A t-stat greater than 2 and a p-value below 5% generally indicate that a variable contributes meaningfully to explaining the dependent variable." 3 TR 963. Variables that fall outside these tolerance ranges should be excluded.

Staff's newly introduced constant variable tested far outside these ranges. According to Mr. Breuring, Staff's constant variable had "a t-stat of 1.43 and a p-value of 15.54%, suggesting it is statistically weak and unlikely to enhance the model's predictive accuracy." 3 TR 963. Although including a statistically weak variable does not always degrade a model's predictive accuracy, it does not contribute meaningful explanatory power and should be carefully considered. 3 TR 964. Such a variable may simply add noise rather than insight. In this case, to the extent that Staff's constant variable skewed Staff's projected annual commercial growth rate, which is clearly skewed as Figure 2 showed, it was harmful.

In its briefing, Staff criticized the Company for using two separate models: a "use-per-customer" model and a "total delivery" model (i.e., a commercial delivery model that combines bundled and choice customers). Staff's Initial Brief, pages 97-98. Staff used only the use-per-customer model, saying that it "gives more accurate forecasts of load over a recent timeframe." Staff's Initial Brief, page 97. "While each model has its own strengths and weakness, using both offers a "more balanced analytical perspective." 3 TR 964-965. Plus, using both models allowed for "cross-validation between different forecasting perspectives. 3 TR 964. Although Staff questioned the accuracy of the hybrid approach, see Staff's Initial Brief, pages 102-104, the Company confirmed its accuracy by showing the results are consistent with historical trends and makes sense of the economic landscape. See Company's Initial Brief, pages 302-303-validation between different forecasting perspectives. 3 TR 964. Although Staff questioned the accuracy of the hybrid approach, see Staff's Initial Brief, pages 102-104, the Company confirmed its accuracy by showing the results are consistent with historical trends and makes sense of the economic landscape. See Company's Initial Brief, pages 302-303.

Staff's decision to rely on a single regression model without considering whether the results were consistent with historical trends or the economic landscape was a gamble without any backstop. Although regression modeling is critically important, it is equally important not to put modeling before the modeler's expert judgment, which serves as a valuable check on the models. 3 TR 960-962. A modeler's expert opinion about trends and the overall economy allow the modeler to see and test model results to account for factors the models may have missed. Mr. Breuring applied these principles when forecasting the Company's overall electric deliveries, including its commercial bundled deliveries, by evaluating two different model results and considering the results in light of his years of modeling experience and expert judgment. *Id.*

Concerning the constant variable in its model, Staff acknowledged that its statistical significance is measured using its p-value and t-statistic, Staff's Initial Brief, page 103, n22, but sought to downplay statistical significance by observing that "while important, [it] is not the primary concern of a forecasting model." *Id.* at 103. Yet, Staff also said that "[a]n ideal model is one that is both highly accurate and uses variables [to] explain what causes variation in either load or customers with a high degree of certainty (as measured by t-statistics and p-values)." *Id*. at 103 (emphasis added). In short, Staff said that statistical significance is *not* a primary concern but that an ideal model nonetheless uses statistically significant variables. There is a tension in these statements that the Company's position relieves. Statistical significance *is* a primary concern, which is why an ideal model uses statistically significant variables.

Staff's portrayal of an ideal forecasting model describes the Company's models. The Company's models are accurate and statistically significant, as demonstrated by the models' adjusted coefficient of multiple determination ("$R_a^2$"), Mean Absolute Percent Error ("MAPE"), and their variables' strong "p-values" and "t-statistics." As discussed further below, these metrics

together showed that the models and their variables were both accurate and relevant. 3 TR 939-941, 963. Further, the Company's forecast – based on the models and its expert's independent evaluation of economic trends and variables – explained variations in commercial bundled deliveries. Variations were being driven by electric vehicle growth and EWR savings. 3 TR 957-958.

Holistically, considering the predictive accuracy of the Company's models and their explanatory power, as well as the adjustments that the Company made to the modeling results in keeping with historical trends, the Company's forecast is better.

**b. Response to the ALJ's Reasons for Adopting Staff's Proposed Adjustments**

The ALJ adopted Staff's forecast. Although he found "Consumers' description of recent historical commercial trends noteworthy," he did not agree that "historical trends are more important than model accuracy." PFD, page 566. The Company shares this view, which is no reason to reject the Company's forecast. Both historical trends and model accuracy are important. The Company's forecast is the only one that is consistent with historical trends and produces accurate results – not to mention the only one that makes sense of the economic landscape. If the ALJ had considered the Company's Reply Brief as it was originally filed, he would have seen the Company's arguments on this point and been forced to grapple with them. Instead, the ALJ dismissed the Company's position based on what appears to have been a misunderstanding (misinterpreting the Company's position as support for historical trends at the expense of model accuracy when, in reality, both are important). The Commission should reject the ALJ's proposal.

The Company demonstrated that its forecast is consistent with historical trends and accurate. Figure 2 in Mr. Breuring's rebuttal testimony, depicted earlier in this section, shows that the Company's forecast is consistent with the historical trend. 3 TR 959. As for accuracy,

Mr. Breuring explained how he tested for accuracy using $R_a^2$ and MAPE values. "The $R_a^2$," he said, "measures the ability of the models to explain variations in the historical data." 3 TR 939. If a regression model has an $R_a^2$ value of 0.9 or more, it explains at least 90% of the data variation. 3 TR 939-940. MAPE, on the other hand, is "used to measure the model errors in which smaller values suggest better model performance." 3 TR 940. MAPE values below 3% are generally considered ideal.

The Company's regression models have strong $R_a^2$ values between 0.90 and 0.97 and equally strong MAPE values between 0.2% and 2.1%. 3 TR 940. Staff's model also had strong $R_a^2$ and MAPE values, but Staff adjusted its model results after testing for these values, see Staff's Initial Brief, pages 100, 102, which calls the values into question. As already noted, Staff used the Company's adjustment – as an absolute value without refining it – that the Company had tailored for its regression models to align with observed growth rates over the past 12-24 months. 3 TR 962. The differences between Staff's and the Company's models required different adjustments. *Id.* By applying the Company's adjustment without refinement, Staff skewed its model results and undermined otherwise solid $R_a^2$ and MAPE values.

At a minimum, if the Commission chooses not to adopt the Company's model results, it should instead use Staff's *unadjusted* model results. The primary reason the ALJ gave for adopting Staff's forecast is that its regression model performed better statistically (measured before Staff applied its adjustment). If the Commission accepts this, the forecast should rely directly on the unadjusted model results. Further, the Company modified its regression output to align its forecast with expected outcomes. If these adjustments are viewed as a weakness in the Company's forecast, which is how the ALJ viewed them as discussed below, consistency would require using the Staff's

regression results without adjustment. Staff's adjustment to its model results increased sales, so without the adjustment, Staff's model results would be closer to the Company's forecast.

According to the ALJ, the Company "did not demonstrate that the use of manual adjustments to align model output with historical trends produced more accurate or robust forecasts." PFD, page 566. This ignores the Company's testimony about growth factors that explain why a manual adjustment was necessary. EWR savings are reducing projected growth by 1.8% each year, and although growth has partially offset these savings, there is not enough growth in the commercial sector in the Company's service territory to fully offset these savings or to allow for a 1.0% growth rate as Staff forecasts. 3 TR 962. Mr. Breuring discussed the key growth factors:

- **Historical Trends:** Commercial electric consumption has stabilized post-pandemic, with minimal growth from 2022 to 2024 [due to sustained EWR savings not sufficiently counterbalanced by other growth drivers]. The [Staff's] proposed increase contradicts this trend.

- **Economic and Customer Growth Indicators:** Economic indicators and customer count growth are modest (CAGRs of 0.1%–0.17%), insufficient to justify the proposed increase.

- **EV Adoption:** Growth in EVs is already factored into the Company's forecast. Additional EVs required to support Staff's adjustment would imply a 24% underestimation, which is highly unlikely. [3 TR 957-958, 966.]

Without a manual adjustment, the Company's forecast would not have adequately reflected these growth factors.

The ALJ also found that Staff's constant, or intercept term, did not affect the accuracy of Staff's model. The ALJ did not explain the reason for this finding – presumably relying exclusively on Staff's arguments. Yet, Staff itself conceded that an ideal model should "explain what causes variation in either load or customers with a high degree of certainty (as measured by t-statistics and p-values)." Staff's Initial Brief, page 103. Neither Staff nor the ALJ disputed that

Staff's intercept term had a weak t-statistic and p-value. So, even if Staff's intercept term did not skew the accuracy of Staff's model, it was not, by Staff's own reasoning, ideal.

For all these reasons, the Commission should adopt the Company's commercial load forecast, as it is both accurate *and* consistent with historical trends. If not, the Commission should, at a minimum, adopt Staff's model results without adjusting the output as Staff did.

#### 2. Total Electric Operating Revenues

Given the adjustments to the commercial load forecast, the ALJ also recommended that the Commission revise the Company's total operating revenues accordingly. PFD, page 567. If the Commission rejects the adjustments to the Company's commercial load forecast, it should likewise reject the adjustment to total operating revenues.

### B. Other O&M Expense

#### 1. Distribution O&M Expense

##### a. Electric Operations

###### (i.) Non-Forestry Reliability

The requested test year funding in LVD Lines Reliability is $3.5 million to maintain disconnect switches, $2.2 million for groundline pole inspections, $500,000 for padmount inspections, and $1.8 million for other LVD inspections. 3 TR 1503. Historical spending in this sub-program was not sufficient to complete all of the Institute of Electrical and Electronics Engineers recommended work, and the requested funding is needed to increase maintenance work and perform the needed inspections to replace deteriorated LVD poles. *Id*. This work will benefit customers by reducing outages caused by failed equipment, improving public safety, improving power quality, and reducing electric load. 3 TR 1501-1502.

The PFD stated that based on the Company's LVD Lines Reliability spending for the first six months of 2025, the PFD does not expect that the Company will spend an additional $7 million

in the remainder of 2025. PFD, pages 575-576. The PFD recommended a $5.684 million disallowance based on this review of the actual spending in the first half of 2025. PFD, page 576. The Commission should reject the PFD's recommended expense reduction because it would not be reasonable to approve projected test year O&M, which begins in May 2026, based solely on the actual spending in the first six months of 2025.

Following the catastrophic ice storm and subsequent severe weather experienced in March and April of 2025, the Company was required to constrain its O&M spending in the first half of 2025. 3 TR 1580. The severe weather caused widespread damage to the Company's electric grid, and resulted in the Company seeking Commission approval to defer the O&M expenses associated with the storm for future recovery. The Commission granted the deferral request on June 12, 2025 in Case No. U-21914, which allowed the Company to again focus on additional O&M-related activities. 3 TR 1580-1581. In addition, many programs do not follow a linear monthly spend, and thus it is not reasonable to base future projections on the first six months of spending in a year. *Id*. As shown in Exhibit A-219 (MPK-29), line 1, LVD Lines Reliability O&M was constrained in the first half of 2025 but has since increased, and the Company fully plans to spend the projected amounts in the test year. 3 TR 1581. The Commission should not adopt the PFD's reduction in this reliability funding, which will result in the Company unable to achieve the significant benefits planned for customers.

The LVD Substations Reliability O&M sub-program supports substation equipment inspections, recloser and circuit breaker test operating, and substation battery maintenance. 3 TR 1505. The sub-program also supports Metro and environmental inspections. 3 TR 1505-1506. These inspections are based on manufacturers' recommendations, industry best practices, and the Company's experience with the equipment. 3 TR 1506. The average substation outage resulted

in 0.30 SAIDI minutes (the equivalent of 3,110 customers out of service for 180 minutes), and an Easton substation outage in 2024 resulted in 0.59 SAIDI minutes (3,187 customers interrupted for 346 minutes). 3 TR 1507. The inspections performed under this sub-program help avoid these significant substation outages, with each avoided outage providing a substantial benefit to system reliability. *Id*.

The PFD recommended approval of Staff's proposal to reduce the projected LVD Substations Reliability O&M expense from the projected $5.475 million test year amount to $3.935 million based on actual spending in the first six months of 2025. PFD, pages 585-587. The Commission should reject this recommended reduction because the LVD Substations Reliability O&M spending is not linear during the year. 3 TR 1582. Spending in this sub-program is typically lower in the winter and spring but ramps up in the summer and fall. As shown in Exhibit A-219 (MPK-29), line 2, the Company's spending in the third quarter of 2025 was nearly as much as the spending in the first half of the year, and the Company is on track to spend $4.65 million in 2025.

Approval of the Company's proposal to increase funding in this sub-program is important because historical funding has not been sufficient to complete inspections on the schedule giving in the ESR-1 guidelines, and the increased O&M funding is to clear maintenance backlogs and get the Company on the appropriate inspection schedules. 3 TR 1507-1508. The Commission should approve the projected funding for the test year to allow the Company to accomplish these important inspections and maintenance activities. *Id*.

**(ii.) <u>Operations, Maintenance, and Metering</u>**

HVD Lines Demand O&M funds the repairs to 46 kV and 138 kV lines equipment, specifically non-capital HVD failures identified in routine inspections or emergent events. 3 TR 1511. Work in this sub-program mitigates large and long outages that would occur when HVD assets fail. *Id*. The increased projected expenses in this sub-program of $2.979 million in the test

year will address a backlog of repairs and the continued fixing of anomalies as they are found. 3 TR 1512.

The PFD recommended approval of Staff's proposal to reduce the projected test year HVD Lines Demand expense by $2.451 million based on the actual spending in the first six months of 2025. PFD, pages 591-593. The Commission should reject this recommended reduction because it does not reflect the work that the Company will perform in the projected test year. The Company has identified sufficient O&M work to be funded by the test year projection. 3 TR 1583. And the Company is projecting a modest increase in HVD Lines Reliability work in the test year, which will allow the workforce to complete more HVD Lines Demand work in 2026 and 2027 to meet the projection. 3 TR 1592-1583. The Commission should approve the projected expense to fund the Company's ability to perform repairs and upgrades that will prevent outages and improve system integrity and reliability. 3 TR 1511.

Consistent with the request the Company made in its most recent natural gas rate case in Case No. U-21806, the Company requested approval to defer for refund or recovery of any O&M expenses in the Staking and Locating Program amounts below or above the amounts included in rates for the test year. 3 TR 1524. In the Commission's U-21806 Order, page 212, the Commission approved the proposed regulatory deferral mechanism for this program with the conditions proposed by Staff. The PFD also recommended approval of a deferred accounting mechanism in this case, but only for fluctuations tied to ticket volume variability and with the other conditions outlined by Staff. PFD, page 608.

The referenced Staff conditions were presented by Staff witness Jacob G. Martus. Mr. Martus supported the staking regulatory deferral, but only for fluctuations stemming from the variability in staking volume, and with a cap on the staking volume increase of 3.77% and a cap

on the staking volume decrease of 9.13%. 6 TR 4479-4480. In its Initial Brief, Staff stated that the Company's desire for a symmetrical cap was reasonable, and proposed a 3.77% cap to apply to both increases and decreases. Staff's Initial Brief, page 183.

The Company does not agree that there should be a cap on the recovery or refund amounts based on historical volume fluctuations when the purpose of the deferral mechanism is to address future uncertainty about staking volumes that is largely due to new rural broadband programs. 3 TR 1578. The Company's actual staking volume for January through September 2025 is 411,518, or 22.5% higher than the staking volume in January through September 2024. 3 TR 1577-1578. This increased staking volume compared with 2024 is significantly higher than the 3.77% capped amount on staking volume increases adopted by the PFD. See 3 TR 1578. If the Commission determines that a cap is appropriate, the Company agrees that the cap should be symmetrical, but recommends a symmetrical cap of 10% for both increases and decreases in the staking volume. *Id*.

The PFD also recommended approval of Staff's proposed $1.517 million reduction in the Staking and Locating expense. PFD, page 608. Staff witness Ally Durfee argued that the Company's anticipated 7% increase in Staking volume was based on statewide annual growth and that the Company's growth rate is consistently lower than the statewide average. 6 TR 4430-4431. Staff calculated a projected expense based on a 2.28% annual growth rate and recommended reducing the projected expense by $1.517 million. 6 TR 4431. The Commission should reject Staff's recommended reduction, adopted by the PFD, because the expected Staking growth rate is higher than the historical growth rate due to expansion of rural broadband infrastructure. 3 TR 1583. The Company's 2025 staking volume through September is 411,538, which puts the Company on track to have a staking volume of 520,000 in 2025. This is substantially above the

staking volume amount that Staff used to calculate the projected test year expense (see 6 TR 4431) and higher than any of the annual amounts the Company originally projected through 2027 in this case. 3 TR 1522, 1584. The Commission should approve the Company's projection because it reflects the expansion of rural broadband infrastructure and is supported by the actual staking volume in 2025.

The Alma Equipment Repair O&M sub-program, based in the Company's Alma Service Center, funds maintenance activities for assets such as mobile substation equipment, substation oil processing equipment, and substation power transformer cooling equipment; end-of-life retirement of failed and aged electrical equipment; substation equipment acceptance testing; and compliance with environmental regulations regarding polychlorinated biphenyl ("PCBs"). 3 TR 1532-1533. The PFD recommended approval of Staff's proposal to reduce the expense from the projected $571,000 test year amount to $370,000, again based on actual spending in the first six months of 2025. But again, the spending in the first six months of 2025 does not necessarily indicate what the Company will spend in the test year that begins in May of 2026. In fact, the work in this sub-program has been relatively consistent in recent years, and the projected test year expense is only slightly higher than the five-year average of $530,000 to account for increased maintenance needed for additional mobile substations. 3 TR 1533-1534, 1584. Given the consistent spending in this program, a five-year average is a better approximation of what the Company can spend in a given year since it accounts for some variation that can occur on an annual basis. 3 TR 1584. The Commission should approve the Company's requested funding needed to perform the planned activities in this sub-program.

**(iii.) Field Operations**

The Tools O&M sub-program includes the cost of procuring tools valued under $1,000, including safety devices, testing equipment, utility-specific industry tools, and fire-retardant

clothing. 3 TR 1541. The availability of these tools enable safer and quicker outage responses, safe and efficient installation of new services, and more productive completion of projects with less waste and lower unit costs. *Id*. And tools such as fire-retardant clothing and other personal protective equipment are essential for employee safety and are required by the Occupational Safety and Health Administration regulations. *Id*.

Staff witness Durfee recommended a reduction based on the Company's actual spending in the first six months of 2025 and proposed to reduce O&M expense from the projected $1.982 million test year amount to $925,000. 6 TR 4432-4433. The PFD acknowledged Staff's concern, but recommended setting the expense at $1.256 million in the test year, which is the lowest amount in the last six years. PFD, page 618. Appendix C to the PFD, line 13, lists this O&M reduction as $1.057 million. While Staff had proposed a $1.057 million reduction, the PFD is recommending a reduction of $726,000.

Although the Company appreciates the PFD's proposed increase compared with Staff's proposed reduction, the Commission should approve the Company's full Tools test year projection. The Company's projected spending was determined based on the size of the field operations workforce, with the spending increase driven by the projected increase in that workforce. 3 TR 1542; see also Exhibits A-178 (CMT-1) and A-179 (CMT-2) for planned increases in electric operations full-time employees. The Company's $1.982 million projection is slightly higher than the five-year average of $1.643 million to support this necessary increase in workforce. See 3 TR 1585. The Commission should approve the requested Tools funding to support the Company's ability to safely and efficiently restore outages, complete reliability projects, and install new services.

The Underground Workforce O&M expense funds the workforce needed to complete undergrounding work in subdivisions and new business services, relocations, and reliability projects, plus the additional undergrounding work that the Company has proposed in this case. 3 TR 1546. This group can also replace failed underground. *Id*. The PFD recommended approval of Staff's proposal to reduce O&M expense from the projected $2.236 million test year amount to $603,000 based on spending in the first six months of 2025. PFD, pages 619, 631-632. The Commission should reject this proposed reduction because the Company was not performing significant undergrounding work in the first six months of 2025. 3 TR 1585. But in the test year, the Company is planning to complete 50 miles of OHUG conversions, which will lead to higher O&M costs for the underground workforce. The Company's projected spending includes $1.106 million for new business and failure work, and $1.130 million for the new OHUG conversions proposed for the test year. 3 TR 1546. The Commission should approve the workforce funding needed to perform this planned undergrounding work.

**2. <u>Line Clearing</u>**

In this case, Consumers Energy announced a new vision for its line clearing program that will lead to fewer tree-caused outages on its system, improving electric reliability for its customers in all conditions. To achieve this, the Company proposed moving to a five-year line clearing cycle for its LVD system by the end of the 2030-2031 test period while maintaining its four-year clearing cycle for its HVD system. More aggressive line clearing, defined as canopy removal, on targeted LVD three-phase primary lines is also a focal point of the Company's vision. At the same time, the Company is proposing to perform deeper causal analysis of tree-caused outages on its LVD system to provide valuable insights and inform future line clearing decisions. 3 TR 2198-2199.

It is an understatement to say that this is a significant undertaking, which is why the Company has a plan and is already taking steps to position itself for success. The Company has

identified three focus areas as it prepares: (1) line clearing contractors; (2) contract planning and supervision; and (3) internal staffing. To ensure it can increase crew resourcing levels, the Company is working with established line clearing contractors to upskill the current workforce and hire additional employees. Plus, the Company is pursuing contracts with other line clearing contractors that can deliver out-of-state tree crews needed to execute the ramp-up plan. 3 TR 2232.

Besides crews, the Company's Forestry Operations and Supply Chain departments are also collaborating with its established contract planning vendor and other vendors who can provide additional planning and supervision resources. For in-house staffing, the Company continues to recruit graduates from Michigan Technological University, Michigan State University, and other universities that offer degrees in forestry or natural resource management. During the ramp-up period, however, the Company will primarily rely on supplemental contract personnel to meet the increased staffing needs over the baseline resourcing level. 3 TR 2233.

With a plan to achieve its vision and the gears already in motion, the Company is well-positioned to reduce its line clearing cycle and secure the resulting reliability benefits. By moving the LVD system to a five-year clearing cycle, the Company projects that tree-caused primary outage incidents will decline by 30% (below 2025 levels), which will in turn lead to a 29% reduction to SAIDI and a 27% reduction to System Average Interruption Frequency Index over the same time. 3 TR 2212-2213. Core aspects of the Company's plan went unchallenged in this case, and the ALJ recommended that the Commission approve these undisputed aspects, including the Company's proposal to move its LVD system to a five-year line clearing cycle, and other aspects of the plan without modification.

In addition to the five-year line clearing cycle, the ALJ also recommended that the Commission approve the associated line clearing expense and reject ABATE's proposed

adjustment, approve the Company's plan to defer $22.24 million of LVD ramp-up costs, and approve its canopy removal proposal. PFD, pages 660-661. As for aspects of the Company's plans that were challenged, the ALJ rejected most challenges. For example, the ALJ rejected a recommendation that the Company clear 100% of first zone canopy and a proposal that the Company file a new analysis of the costs and benefits of a four-year cycle in its next rate case (instead deferring this analysis until the Company has achieved a five-year cycle). PFD, pages 661-662.

There were only a few findings on the topic of line clearing that merit further discussion – findings that the Commission will likely want to modify or at least clarify. For one, the ALJ found that "Consumers should spend the entire amount of line clearing expenses approved in this and each rate case and trim all proposed miles, and if unable to do so, explain how the unspent amounts were reallocated." PFD, page 660. The Company is not opposed to a requirement that it spend its approved line clearing expense during the projected test year as it has done exclusively for many years. Indeed, the Company's proposed Distribution Deferral Mechanism, as a continuation of the previously approved mechanism, is already contingent on test year line clearing spending. See 3 TR 1075; 6 TR 4447. Importantly, as it currently does, the Company should continue to have operational flexibility to accelerate or postpone plans to clear some line miles.

The ALJ also recommended that the Company be "required to collect available data on the costs and benefits of 100% first zone canopy removal from its benchmarking partner utilities and estimate the costs and benefits of such a plan and present its findings in its next rate case." PFD, page 661. The Company generally supports these recommendations with two caveats. First, the Company's ability to benchmark its peer utilities depends on data in other utilities' possession, so the requirement should be couched in terms that recognize this. Second, the Company needs time

to carry out the canopy removal it proposed in this case to collect the data to estimate the costs and benefits of additional canopy removal on its LVD system. The Company expects it will have data to fulfill this request by the 2028 Annual Line Clearing Report filed approximately two years from now.

Finally, the ALJ agreed with Staff's concerns that "contractor costs could cause Consumers to fall behind its line clearing ramp-up timeline and recommends that Consumers be directed to mitigate its contractor costs, such as by negotiating lower costs or by having Company crews perform more line clearing work." PFD, page 662. The Company's ramp-up timeline accounted for increased contractor costs, 3 TR 2227, and the Company has outlined a crewing plan it believes will enable the ramp-up and is attainable given projected crew availability throughout the ramp-up, informed by conversations with vendors. See 3 TR 2202, 2215-2216, 2239. To be clear, the Company has no in-house line clearing crews as the ALJ believed; it instead relies on local and out-of-state contractor crews. See 3 TR 2233. The Company is mitigating contractor costs by relying on less expensive in-state crews whenever possible, managing the work efficiency of the crews, among other tactics.[18] 3 TR 2232-2233. The Commission should reject or at least modify this proposal.

The Company is eager to carry out a new vision for its line clearing program that will lead to fewer interruptions for customers, and it appreciates the overwhelming support it received from the ALJ and stakeholders. With the caveats and one exception noted above, the Company accepts the ALJ's recommendations on this topic.

[18] Further, although not stated in the record because no party recommended that the Company negotiate lower costs, as the ALJ did, the Company always negotiates in good faith to obtain the best outcome for customers – both in terms of cost and quality.

### 3. Service Restoration O&M Expense

In this case, the Company proposed a re-baselined, realistic budgeting approach, as recommended by Liberty, which was complemented by the Company's Service Restoration Resiliency Fund ("Resiliency Fund" or "Fund") and Extraordinary Storm Accounting proposals. The ALJ recommended that the Commission approve the Company's re-baselined service restoration expense but that it reject the Company's proposed Resiliency Fund and Extraordinary Storm Accounting even though they include guardrails to ensure that customers benefit from the proposals. The Commission should adopt the ALJ's recommendation to approve the Company's proposed re-baselined service restoration expense and approve it together with the complementary Resiliency Fund and accounting proposals.

#### a. Service Restoration Resiliency Fund

The Resiliency Fund is proposed as a reserve fund for surplus service restoration dollars when the Company spends less than authorized. The fund would be capped at $30.7 million in the test year, with any additional surplus dollars beyond $30.7 million refunded to customers through a bill credit. Any balance in the Fund would then be used in a future year as the first source of funds if actual service restoration costs exceed authorized, or base, spending levels. In short, the Fund ensures that every customer dollar allocated to service restoration is either used to restore customers' power or is returned to customers as a credit. 3 TR 2143.

Mr. Snider discussed three scenarios to illustrate how the Resiliency Fund would operate in practice:

- In Scenario 1, the Company underspends the base funding amount by $40 million in the test year resulting in a $40 million surplus. The mechanism would allow the Company to transfer $30.7 million of the $40 million to the Resiliency Fund, which is capped at $30.7 million, and refund the remaining $9.3 million surplus balance to customers.

- In Scenario 2, the Company underspends by $20 million in the test year and is able to deposit the entire $20 million into the Resiliency Fund to be used for service restoration expenses in a future year. There would still be room in the Fund to accrue an additional $10.7 million in a later year if the Company underspends again.

- In Scenario 3, the Company overspends the base funding amount by $5 million in the test year, resulting in no transfers to the Resiliency Fund or customer refund. 3 TR 2144.

Figure 5 from Mr. Snider's testimony visually depicts these scenarios in a table:

**Figure 5 - Resiliency Fund Year One Example**

| Scenario | Base Funding Amount | Restoration Spend | Resiliency Fund Balance | Customer Refund |
|---|---|---|---|---|
| 1 | $165M | $125M | $30.7M | $9.3M |
| 2 | $165M | $145M | $20M | $0 |
| 3 | $165M | $170M | $0 | $0 |

3 TR 2144.

The Resiliency Fund comes at no additional cost to customers – it is simply a rainy-day savings plan. The Resiliency Fund ensures all dollars allocated to service restoration are spent on service restoration or refunded. 3 TR 2146. Savings are captured in the Fund for no other reason than to benefit customers, literally, on a rainy day. 3 TR 2147. Despite its merit, some parties opposed the proposal. Staff opposed the mechanism because, among other reasons, Staff supported the Company's full proposed service restoration expense and questioned whether customers will see a benefit from this proposal. 6 TR 4399. The Attorney General and MNSC similarly objected and further argued the Fund is complex and similar to past proposals.[19] 3 TR 2572-2573; 6 TR 4066-4071.

[19] Although Attorney General witness Coppola was skeptical of the Company's proposed Resiliency Fund and its Extraordinary Storm Accounting proposal, Mr. Coppola indicated he could support a decision to discuss these proposals in further detail in a generic docket. 3 TR 2573. This recommendation is discussed in the next section.

Contrary to objections, Mr. Snider explained that "[s]ince the fund will either supplement existing service restoration resources or be refunded to customers, there is only customer benefit and upside from this proposal." 3 TR 2171. Further, the Resiliency Fund is not overly complex or similar to previous Company proposals. "Simply stated," Mr. Snider said, "the Resiliency Fund captures underspent service restoration dollars from prior years and saves them for future use if actual spending exceeds authorized amounts." 3 TR 2171. As for comparisons to recovery mechanisms proposed in earlier cases, previous mechanisms dealt primarily with overspending, while the Resiliency Fund deals only with underspent amounts and treats underspending different than past mechanisms that did address it. *Id.*

The Resiliency Fund is also designed to operate in tandem with the re-baselined O&M expense. If the Company experiences a year when its service restoration expense is lower than its projected expense – what Mr. Coppola describes as a "valley" – then the difference would be deposited in the Resiliency Fund and would be available to offset expenses in the following year if it is what Mr. Coppola describes as a "peak" year when service restoration expenses are higher than projected. 3 TR 2171, 2572.

The ALJ considered the Resiliency Fund together with Extraordinary Storm Accounting and recommended that the Commission reject them. He echoed the sentiment of intervenors who said that the measures shift cost volatility risk to the Company's customers and undermine incentives to control costs. PFD, pages 691-692. In reality, there is no downside for customers. Concerning the Resiliency Fund, it will "either supplement existing service restoration resources or be refunded to customers." 3 TR 2171. It does not shift risks or undermine incentives.

The Commission should approve the Resiliency Fund as a complement to the re-baselined service restoration expense.

### b. Extraordinary Storm Accounting

Extraordinary Storm Accounting, as the name suggests, would allow the Company to use deferred accounting for extraordinary storms that exceed base spending levels. A storm would qualify as "extraordinary" if it causes at least 300,000 customer outages over seven days or leads the Governor to declare a State of Emergency for the affected area. A recent example of an extraordinary storm is the catastrophic ice storm experienced in March and April of 2025 described as the "worst ice storm in modern times." 3 TR 2126, 2147. Under the Company's proposal, expenses incurred to restore power after an extraordinary storm could be deferred and later recovered if the Company demonstrates that the expenses were reasonable and prudent. As Mr. Snider explained, if an extraordinary storm requires the Company to spend more to restore power than the base spending level, "the Company would seek deferred recovery from the Commission by demonstrating the reasonableness and prudence of the restoration expenses in a future rate case." 3 TR 2147. Amounts spent in response to other storms not classified as "extraordinary" would not qualify for deferred recovery.

Extraordinary Storm Accounting is needed because "[e]xtraordinary storms, which present challenging restoration conditions and cause significant damage to Company assets, are the main cause of increased service restoration spending and pose the largest risk to sustainable service restoration operations." 3 TR 2148. The catastrophic ice storm discussed earlier is a case in point. If the Company had not received deferred accounting treatment for this storm, it would have drained most of the Company's service restoration O&M budget for the year. When storms like this strike, even perfectly executed pre-planning and restoration can result in a costly, multi-day restoration effort costing over $100 million.

As disruptive and costly as these storms are, they are also fundamentally unpredictable. It is impossible for the Company to predict, as it is building a rate case, how many of these storms will pass through its service territory in any given year and likewise impossible to accurately predict the resources needed to respond to them. Deferred accounting, which recognizes the heavy costs the Company incurs to safely and quickly restore power after extraordinary storms, will help the Company ensure a reliable and resilient grid. Preparing for a future where weather events like the catastrophic ice storm are more frequent requires establishing deferred accounting where the Company can apply for timely rate recovery in response to these events. 3 TR 2148-2149.

This should be reason enough to approve the Company's proposal, but Mr. Snider also pointed out that Liberty suggested deferred accounting as a possible solution to the Company's restoration budgeting problem and that other state regulatory commissions have approved deferred accounting mechanisms for their utilities. 3 TR 2149-2150. Further, as he did for the proposed Resiliency Fund, he meticulously walked through three scenarios to illustrate how Extraordinary Storm Accounting would operate in practice:

- In Scenario 1, the Company incurs $50 million in restoration costs after an extraordinary storm, which leads the Company to spend $30 million more than its base funding level for the year. Because the extraordinary storm caused overall spending to exceed base funding levels, the Company will seek deferred recovery for the $30 million in excess costs.

- In Scenario 2, the Company also incurs $50 million in restoration costs after an extraordinary storm, but the Company's costs do not exceed the base funding level. Since the calendar year budget covered the Company's restoration needs for the year, Extraordinary Storm Accounting is not an option despite the extraordinary storm.

- In Scenario 3, the Company overspends its base funding level by $10 million, but extraordinary storms did not drive the spending, so Extraordinary Storm Accounting is not an option. 3 TR 2150.

Figure 6 from Ms. Snider's testimony visually depicts these scenarios in a table:

**Figure 6**
***ESA Year One Example***

| Scenario | Base Funding Amount | Total Restoration Spend | Emergency Storm Costs | ESA Deferred Recovery Amount |
|---|---|---|---|---|
| **1** | $165M | $195M | $50M | $30 M |
| **2** | $165M | $165M | $50M | $0 |
| **3** | $165M | $175M | $0 | $0 |

3 TR 2151.

The same parties who opposed the Company's proposed Resiliency Fund opposed its Extraordinary Storm Accounting proposal. Staff witness Theresa McMillan-Sepkoski opposed the proposal because she said the current ex-parte process can be used to request deferred accounting for extraordinary storms, as the Company did for the catastrophic ice storm discussed earlier. 6 TR 4516-4517. She also testified that there is no defined cost threshold, describing the proposal as an open-ended mechanism that she did not view as a best practice. 6 TR 4517. Attorney General witness Coppola and MNSC witness Richard J. Bunch also object to the Company's proposal, although they at times appeared to conflate Extraordinary Storm Accounting with the Resiliency Fund proposal. Mr. Bunch suggested that the Company's proposal would shift risk to customers like past proposals that have been rejected, while Mr. Coppola suggested opening a separate docket to debate the issue. 6 TR 4067.

The Company did consider a cost threshold when developing its proposal but ultimately decided it was impractical. Given the lack of a cost threshold, the Company committed to provide comprehensive storm data, like capital and O&M unit costs for internal and contractor crews broken down by category, to demonstrate that it restored power in a cost-effective manner. Recovery will ultimately be subject to a prudency review in a future rate case. 3 TR 2172. As for

the ex-parte process, the Company's proposal is better than this process because it would create a standardized mechanism, unlike an ex-parte filing, which can be filed any time and has fewer guardrails (e.g., there is no customer outage threshold for an ex-parte filing). 3 TR 2173.

In response to Mr. Bunch, Extraordinary Storm Accounting is not like past proposals that have been rejected. Earlier proposed recovery mechanisms did not differentiate extraordinary storms from other catastrophic categories of storms. 3 TR 2173. Consider the Service Restoration Cost Sharing Mechanism ("SRCSM") proposed in Case No. U-21585. Mr. Snider observed that the Company's proposal in this case creates both a higher threshold for deferred recovery than the SRCSM (by narrowing the scope of storms that qualify for deferred recovery) and creates a process that gives the Commission an opportunity to review service restoration costs to ensure they are reasonable. 3 TR 2152. Deferred recovery is not automatic. The Company's proposal gives the Commission the final say in a future case.

The context is different as well. This case is the first electric rate case prepared with the Liberty audit findings in mind – audit findings and recommendations that called for a change to service restoration budgeting and specifically endorsed deferral accounting as an effective means for permitting recovery of excess storm costs. Customers would not be exposed to additional restoration costs as Mr. Bunch suggests. Whether the Company is granted deferred accounting for extraordinary storm restoration costs through the Company's proposal or whether it obtains deferred accounting through an ex-parte proceeding, both approaches allow the Company to recover its reasonable restoration costs from customers.

As already mentioned, the ALJ considered Extraordinary Storm Accounting together with the Resiliency Fund and recommended that the Commission reject them. He echoed the sentiment of intervenors who said that the measures shift cost volatility risk to the Company's customers and

undermine incentives to control costs. PFD, pages 691-692. Concerning Extraordinary Storm Accounting, in particular, he pointed to the availability of the ex-parte option as apparent evidence that an accounting mechanism is unnecessary. He does not, however, respond to the Company's argument that its proposal is better than the ex-parte process as a standardized mechanism with built-in guardrails. An ex-parte filing, by contrast, can be filed at any time and has fewer guardrails (e.g., there is no customer outage threshold for an ex-parte filing) than the Company's proposal.

As for the ALJ's suggestion that Extraordinary Storm Accounting would somehow shift risks to customers, this cannot be. After all, the ALJ pointed to the ex-parte process as an alternative to the Company's accounting proposal that already exists, and the ex-parte process, as just noted, is more relaxed than the Company's proposal. Without a customer outage threshold, the ex-parte process could lead to more deferred accounting requests than Extraordinary Storm Accounting would. So, if accepting the ALJ's apparent view that deferred accounting requests carry risks for customers, Extraordinary Storm Accounting actually shifts risks *away from* customers in comparison to the status quo.

Finally, concerning the ALJ's statement that Extraordinary Storm Accounting "reduc[es] the Company's accountability for cost control," it does not. Neither the opposing parties nor the ALJ were able to link the Company's accounting proposal to reduced accountability. They instead sought to compare the Company's proposal to past proposed service restoration mechanisms that were rejected for, among other things, undermining incentives to control costs. PFD, pages 684-685. But unlike past proposals, Extraordinary Storm Accounting would require a prudency review in a future case. 3 TR 2147. Commission review is a clear incentive to control costs.

The Company urges the Commission to approve Extraordinary Storm Accounting to establish a standardized mechanism that would be applied predictably when unpredictable and extraordinary weather strikes.

### 4. Generation O&M Expense

#### a. Corporate Memberships

The Company takes partial exception to the PFD's recommendations related to the corporate memberships expense. The Company agrees with the PFD's recommendation that Consumers filing related to corporate dues and memberships be "consistent with the disclosure standards established for DTE Electric." PFD, page 716. As the Company has stated, it is committed to filing its next electric rate case consistent with the standards in place for DTE Electric. Given the historic approval of these costs and because this issue was already litigated in Case No. U-15245, the Company requests the Commission approve the Corporate Memberships Expense in this case and incorporate the updated filing standards into the Company's next electric rate case filing.

The PFD additionally recommended "the Commission direct Consumers to provide a detailed and itemized list of expenditures, with names of vendors and a detailed description of the nature of the expenses, of Consumers spending on electoral campaigns, advertising, marketing, lobbying, trade associations and 501(c)(3) and 501(c)(4) non-profits." *Id*. It is unclear if the PFD's recommendation is related to the corporate dues expense as it expands the discussion beyond the corporate membership fees and ties to direct Company spending where the issue raised by the Urban Core Collective is related specifically to the Company's Corporate Memberships Expense, which is comprised of membership payments to third parties. Due to the lack of clarity in the second recommendation made in the PFD as related to the Corporate Memberships Expense, the

Company requests the Commission accept the PFD's recommendation only to the extent that it would align the Company's filing standards for its Corporate Memberships Expense with DTE Electric's.

### 5. Information Technology O&M Expense

Exhibit A-19 (SHB-3) is a Summary of Actual and Projected IT Investments O&M expenses for the years 2024, 2025, 2026, and the 12 months ending April 30, 2027. In 2024, the Company allocated $8,536,000 in O&M expenses to the IT Department for its work supporting technology investments. The Company expects to incur $13,174,000 in IT Investment O&M expenses in 2025; $26,169,000 in 2026; and $26,303,000 for the test year ending April 30, 2027 for IT support provided to technology investments.

There were proposed adjustments to the Company's projected IT Investments O&M expenses, but the ALJ recommended that the Commission reject most of them. The one adjustment the ALJ supported was Staff's proposed adjustment to the Business Continuity – Program Management Tool ("Tool"), which is discussed below.

#### a. IT Investments O&M Expense

The Tool gives the Company continued access to critical IT systems during a business interruption. For example, if the Company is the target of a ransomware attack (or any other event that disables the Company's network), the Tool ensures Company coworkers have access to emergency response plans, ICS forms, and Business Continuity and Disaster Recovery ("BC/DR") plans from any device. See Exhibit A-21 (SHB-6), page 43. The Tool minimizes downtime by providing a critical link between departments and the essential functions they support before, during, and after a disruption. 3 TR 751. The current BC/DR program does not have the same capabilities and requires manual workarounds to prevent losing critical data. *Id.* These

workarounds cost the Company labor hours when preparing for possible events and during events as well. The Tool will save the Company's Emergency Management Department 376 labor hours annually. Exhibit A-21 (SHB-6), page 43.

Despite the benefits of the new Tool, Staff witness Emma Zichi recommended that the Commission disallow all the Company's proposed O&M expenses for this project ($50,579 for the projected test year) essentially because the Company should have proposed the Tool sooner. During discovery, the Company disclosed that it adopted Federal Emergency Management Administrative and National Incident Command System standards in 2013, and the current system does not have the capability to support the requirements. Exhibit S-14.1, page 17. Staff reasoned that if the standard were adopted in 2013, the current system put in place in 2023 should have adhered to these standards. According to Staff, the Company did not explain this inconsistency or why it is proposing a system now that allows it to comply with the standards. 6 TR 4354.

Company witness Baker clarified that while the current tool supports BC/DR functions, it does not support ICS functions consistent with federal standards. 3 TR 775. This was also true in 2023 when the Company bought the current tool. But Ms. Baker explained that in 2023 when the BC/DR tool was approaching the end of its useful life, the Company had to decide on a replacement. Unfortunately, there was not yet – and still is not – a single comprehensive, cost-effective solution that serves both BC/DR and ICS functions. 3 TR 775-776. As a result, the Company decided to acquire the tool that serves BC/DR functions based on its pressing need at the time. 3 TR 776. The new Tool proposed in the current case will fulfill ICS functions needed to coordinate immediate response and command during emergencies. 3 TR 775.

The ALJ agreed with Staff that expenses for this project are unnecessary and imprudent given the Company's alleged "failure to prioritize this project since adopting ICS standards in

2013, including when the Company implemented its current Riskonnect system in 2023 without adequately addressing its related incident management needs." PFD, page 721. The ALJ also questioned "whether the costs for this project will be incurred in the test year as planned, considering the change in implementation dates emphasized by Ms. Zichi and the fact that the Company has yet to select a vendor or a software solution." *Id.*

The ALJ appeared to adopt the Staff's reasoning wholesale, so the Company's response to Staff applies equally to the ALJ's findings. As for the timing of the project, the project's start and end dates are clearly spelled out in Confidential Exhibit A-20 (SHB-5) and not likely to change again given the benefits the Company stands to gain once the project is completed.

**6. Incentive Compensation Expense**

The Company takes exception to two issues from the PFD's recommendation for Consumers Energy's Employee Incentive Compensation Plan ("EICP") expense for the test year. The Company appreciates and agrees with the PFD's recommendation that the Commission approve the Company's full request for its non-officer portion of the EICP expense. However, in connection with the non-officer EICP, the PFD recommended that "the Commission reaffirm its finding that the reduction of methane emissions metric is not an appropriate operational goal for electric employees and should not be included for the purposes of EICP calculations." PFD, page 740. The ALJ overlooked the fact that the Company uses an allocation factor to allocate the total EICP cost between its gas and electric utility so that each utility's customers are only paying the portion of the cost that corresponds to each utility's share of the overall program. 3 TR 1027. As Company witness Amy M. Conrad explains:

> The related incentive expense is then allocated between electric and gas businesses based on multiple factors determined by the Accounting Department based on the type of activities the departments or business units perform. These factors include but are

> not limited to: (i) percentage of time; (ii) property, plant, and investments; (iii) operating revenue; (iv) headcount; and (v) labor. The quantified benefits relate to overall Company priorities. Both electric reliability and methane emission reduction are essential to the Company's organizational priorities. The Company ensures the EICP is quantified to ensure electric customers pay for the benefits they receive and given the combined Company operations it is reasonable to include both goals in the EICP. [3 TR 1027].

Due to the program being balanced in this way, it is reasonable to conclude that the allocation factor sufficiently avoids any subsidization between the two utilities.

Additionally, the PFD recommended that the Commission disallow $192,600 of Consumers Energy's projected O&M expense for its EICP in this case associated with the portion of EICP attributable to the Company's top five officers. PFD, page 739. The PFD stated "the Company will not supply the information it relied on" to calculate the EICP for the top five officers. PFD, page 738. This is inaccurate because the Company has made the information available to Staff for review. Company's Initial brief, pages 376-377. Consumers Energy sought and obtained permission from the third-party owner of the proprietary market data, which allowed Staff to view the materials that helped to inform the Company's top-five officer EICP compensation decision at the Company's offices. The ALJ largely ignored the Company's standing offer to provide the data to Staff, the PFD discussed the publicly available data the Company shared, but did not acknowledge that the Company "has gone to Extraordinary lengths to ensure that Staff is able to review the same information that Consumers Energy's Compensation Committee reviews in order to make its compensation decision for the top five officers." Company's Initial Brief, page 376. The PFD appears to conflate the public data the Company provides in its exhibits with the proprietary data the Company actually uses and has made available to Staff with some restrictions. PFD, pages 732-734. Consumers Energy has been responsive to the Commission's reasons for disallowing the top-five officer portion of EICP in Case No. U-

21585 and other recent cases. The data shows that the Company's EICP for its top-five officers is consistent with (and actually slightly below) the market. The Company's EICP for its top-five officers is reasonable and should be approved.

**7. Productivity Adjusted Inflation**

The PFD stated that the Company "did not provide more detailed evidence demonstrating that it is offsetting inflation by productivity as directed by the Commission in U-21585." PFD, page 753. The PFD is incorrect. In Case No. U-21585, the Commission adopted the ALJ's findings and conclusions related to inflation rates, which included the ALJ's recommendation that the Company "present more detailed evidence to demonstrate that it is in fact offsetting inflation by productivity in the Company's next rate case." U-21585 Order, page 356. In response, Consumers Energy presented testimony explaining how productivity is reflected in the Company's expense projections.

Company witness Heidi J. Myers explained that productivity improvements, such as through process efficiencies, technological integration, or workforce optimization, are not easily shown in traditional financial metrics or reporting frameworks. 3 TR 1833. And productivity does not always mean spending reductions, but instead results in the ability to provide improved service to customers within the same costs. *Id*. But the nature of these types of improvements means that the Company does not have detailed, itemized documentation to show a line item productivity gain in witness exhibits. *Id*.

Ms. Myers further explained that the development of projected costs for many of the Company's programs is more complex than simply applying an inflation factor to historical costs. 3 TR 1833. Each individual Company witness supports the costs they are sponsoring and the methodology used to develop those costs. 3 TR 1833-1834. The Company does not have a single

formulaic methodology for projecting O&M. Rather, the projected costs are supported by the reasonable and prudent methodology that best applies to reach the individual projections. See 3 TR 1850. Ms. Myers offered examples of Company witness testimony and the cost efficiencies or reductions individually supported by these witnesses. See 3 TR 1834-1835, generally referencing the testimony of Company witnesses Sara E. Stewart, Stacy H. Baker, Jessica R. Byrom, Richard T. Blumenstock, Andrew R. Snider, Matthew J. Foster, and Quentin A. Guinn. Accordingly, the Company presented "more detailed evidence" related to productivity as required in Case No. U-21585.

The PFD recommended that in the programs and sub-programs where Consumers Energy increased projected test year costs using inflation, MNSC's proposed productivity adjusted inflation and labor rates should be used to establish the projection. PFD, pages 753-754. The Commission should reject this recommendation because it is a broad, overly simplistic expense reduction that does not consider the individual support for Consumers Energy's projections. The testimony and exhibits presented by the Company must be considered to determine whether the projections are reasonable – the PFD's recommendation fails to conduct this review.

As an example, the Corporate Services O&M expense is an area where the Company generally projects the expense using the Company's inflation rates. 5 TR 3357. However, it is important to note that the Company does not simply take the historical Corporate Services expense and apply inflation factors to project the test year expense. Company witness Foster explained that the Company also makes adjustments to the expense as appropriate to remove one-time costs, reflect transfers of costs into or out of the Corporate Services area, or reflect significant changes in the expense. 5 TR 3357. In this case, the Company removed a one-time consultant expense of $3.812 million from the 2024 historical expense, which reduced the starting point for calculating

the expense from $41.354 million to $37.543 million. See Exhibit A-91 (MJF-2), lines 12 and 14, column (d). The Company then further reduced the projected test year expense by $2.597 million to replace the actual insurance distributions received in 2024 with the five-year average for insurance distributions. 5 TR 3358. Thus, the test year adjusted Corporate Services O&M expense projected by the Company in this case was $36.968 million. Exhibit A-91 (MJF-2), line 15, column (n).

The $36.968 million test year projection is less than the 2024 actual Corporate Services expense of $41.354 million and less than the normalized 2024 Corporate Services expense of $37.543 million. The Company further supported the reasonableness of the Corporate Services projected expense by the fact that S&P Global Market Intelligence ranked Consumers Energy's 2023 electric administrative and general costs (excluding pension and benefits) the third lowest out of 100 top companies ranked on a cost per customer bases for electric utility companies with more than 500,000 customers. 5 TR 3358-3359; Exhibit A-92 (MJF-3). This ranking is a strong indicator that the Company is working to manage overhead costs to keep rates affordable for customers. 3 TR 3359.

This Corporate Services example illustrates the error in the PFD's recommendation to apply a productivity adjusted inflation factor without individually reviewing the reasonableness of the witness projections. It would be unreasonable to further reduce the Corporate Services expense where the Company is already projecting a test year expense that is lower than the normalized 2024 expense, and where the S&P Global Market Intelligence ranking supports the reasonableness of the Company's expense. Accordingly, the Commission should reject the PFD's recommended expense reduction based on productivity adjusted inflation factors.

Finally, the PFD recommended that in future rate cases, "Consumers propose productivity adjustment factors, in addition to inflation rates, and that in those specific programs, with both O&M expenses and capital expenditures, where inflation is applied to future costs, that the PAI be applied." PFD, page 754. The Commission should reject this recommendation. The U.S. Supreme Court has recognized that a utility has a right to "enough revenue not only for operating expenses but also for the capital costs of the business." *Fed Power Comm v Hope Nat. Gas Co*, 320 US 591, 603; 64 S Ct 281; 88 L Ed 333 (1944). Consumers Energy must have the ability to present evidence to the Commission in rate cases supporting the revenue requirement that Consumers Energy believes is necessary to operate the business and make capital investments. The Commission should not force the Company to present productivity adjusted factors to inflation percentages to calculate future cost projections, particularly where the Company does not agree that such a methodology results in a reasonable projection of future costs. Consumers Energy must have the ability to present and support the cost projections that Consumers Energy contends are reasonable and prudent. The other parties are then free to present their recommended adjustments to the Company's projected costs, including recommendations to use different inflation factors.

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

### A. Rate Design

#### 1. Rate Modifications

##### a. Rate LEDR

The PFD properly recommended that the Commission approve a facilities allowance for Large Economic Development Rate ("LEDR") that includes distribution and system contribution revenues and is based on a limited five-year term, which is consistent with the direction given by

the Commission in Case No. U-21585. PFD, pages 815-816. Additionally, the PFD agreed with the Company that the facilities allowance should be offered to an existing LEDR customer if the customer's contract contemplates a future facilities allowance. PFD, pages 816-817. The Company supports these recommendations.

In order to offer the facilities allowance to existing LEDR customers, the PFD proposed that the Company should first obtain from the Commission approval that the contract sufficiently contemplates the facilities allowance. PFD, page 817. This is unnecessary. The Company does not file its LEDR contracts with the Commission. The PFD provides no justification for why the Commission needs to review the contract of a customer which is executed pursuant to an approved tariff rate, and affirm whether the Company is properly applying an allowance provided for under the tariff. While a separate filing is unreasonable, it should be noted that the application of the facilities allowance would be reviewable in a rate case. Accordingly, the PFD's recommendation should be rejected.

## B. Tariff Issues

### 1. Service Connection Fee

Consumers Energy proposed a new overhead service connection fee and proposed to update the existing underground service connection fee for Residential and General service customers. The overhead service connection is proposed to mirror the proposed fee for underground connection and will seek to apply a uniform fee structure for new service installations, regardless of the connection type. 3 TR 1120. This proposal will support customer adoption of the more reliable underground option for services. 3 TR 1120, 1899-1900. This fee proposal will benefit customers because, considering their exposure to weather and trees, storms in the Company's service territory typically affect overhead services much more than underground

services. 3 TR 1900. Over the last 2 ½ years, overhead residential services are about 45 times more likely to fail than underground residential services, and the restoration of residential services are often not completed until near the end of storm restoration since the Company prioritizes work that restores a large number of customers or critical failures such as hospitals. *Id*.

As to the current underground service connection fee, the Company is proposing to increase the fee to reflect cost increases that have occurred since the fees were last updated in Case No. U-9346. 3 TR 1120. The proposed fees are based on a three-year average service connection length of 132 feet. 3 TR 1120. The Company is proposing to replace the current per-foot charge with a flat fee of $1,300 for residential customers and $2,200 for general service customers. 3 TR 1121. These amounts were derived by applying the cumulative inflation rate over the past 31 years to the current per-foot charges multiplied by the 132-foot average service length. *Id*.

The PFD stated that it agrees with Staff that using just a flat fee is not appropriate, and recommended that the Commission direct the Company to create a fee structure that covers the fixed costs but also reflects the variable costs. PFD, page 843. The Commission should approve the Company's proposed updates to the service connection fees in this case and reject the requirement that the Company create a different fee structure. The Company's proposal to charge a flat fee is reasonable because a significant portion of installing a new service involves fixed costs associated with the crew being onsite for the work, and those fixed costs are included in the Company's proposed fee structure. 3 TR 2045. Flat fees also create billing efficiencies that allow the customer to complete payment earlier in the process rather than needing to wait for a full design to be developed. *Id*. Flat fees also prevent the need for rebilling if the actual footage differs from the original quote, improving the customer experience. 3 TR 2045-2046.

The Company also has protections in place in the proposed tariff to mitigate the PFD's concern with subsidization. If the customer does not accept the Company's proposed route, which will generally be the shortest reasonable and cost-effective route, then the customer will be assessed any additional costs incurred by the Company in addition to the flat rate. 3 TR 2046. The proposed tariff language states: "For the route specified by the Company, the contribution shall be a flat fee of $1,300. For an alternate route requested by the customer and is mutually agreed upon by the Company and the customer, the contribution shall be a flat fee of $1,300 plus any additional costs in excess of those associated with the route specified by the Company." Exhibit A-16 (BAG-2), Schedule F-5, pages 6, 10, and 13; see also pages 11 and 14 for the same language with the General Service fee.

The Company's proposal is based on average service length, promotes more reliable underground services, updates stale fees, and provides protections against subsidization. The Commission should approve the Company's reasonable update to the service connection fees, and the addition of the overhead service connection fee, in this case rather than require a new request in the future.

## VI. OTHER ISSUES

### A. Distribution Investment Recovery Mechanism

The Commission most recently approved a Distribution Investment Recovery Mechanism ("IRM") in Case No. U-21585 covering the 12 months ending February 28, 2026. The Company is proposing an IRM that will cover a two-year period beginning with the May 1, 2026 start of the test year in this case. 3 TR 1828. Consumers Energy proposes to continue the IRM with the same investment categories the Commission approved in Case No. U-21585, which were LVD Lines Reliability, Resiliency – Fractionalization, and System Protection, as well as add two new

categories - Repetitive Outages – LVD and Vulnerable Communities. 3 TR 1828-1829. The Company proposes that the spending levels included in the IRM for the 12 months ending April 30, 2027 be set at the test year levels approved for each program in this case, and year 2 of the IRM should be equal to year 1 spending levels. 3 TR 1828. The revenue requirement for the IRM will be used to calculate an IRM surcharge by rate class for the test year. 3 TR 1831. The Company proposes to maintain the IRM process approved in Case No. U-21585, including planning meetings, reporting metrics, and a reconciliation process. 3 TR 1474-1475, 1830.

The PFD recommended reducing the IRM amount by $6.068 million based on the PFD's recommended reductions to the LVD Repetitive Outages expenditures. PFD, page 865. As discussed above, the Commission should reject this recommended reduction in Repetitive Outages work. The PFD also recommended that the Commission only extend the IRM through the test year to allow for further information in the reconciliation proceedings. PFD, pages 865-866. Additional information is not needed before approving a second year of the IRM in this case. The Company has already made one IRM reconciliation filing in Case No. U-21918, and a settlement agreement has been filed in that case. It is unclear what additional information will be gained from the next IRM reconciliation that would help inform approval of a second year IRM in a rate case proceeding.

The PFD stated that "equity outcomes do not appear to be discussed in the IRM reconciliation cases," and thus recommended "the Commission require Consumers to report more thoroughly on the linkage between its investments in EJ communities and the need in those communities in its next rate case or direct that equity outcomes be specifically addressed in the IRM reconciliation." PFD, page 867. The Company is already addressing these outcomes as part of the IRM process. In the Commission's March 1, 2024 Order in Case No. U-21389, page 273,

the Commission noted that consideration of whether investments are being deployed equitably is part of the IRM review process. And in the U-21585 Order, pages 365-366, the Commission noted that based on the advances made by Consumers Energy regarding the use of the EJ flag, development of a regression analysis, and development of the EJ Resiliency Plan (now called the VCRP), and pending the outcome of the planning meeting, approved IRM amounts in that case were "on track for deployment in an equitable manner." The Company included the VCRP in the IRM in this case in response to the Commission's direction that the Company should show how the IRM promotes system equity. 3 TR 1577. The Company will also be tracking the miles of VCRP projects completed as part of the IRM metrics. 3 TR 1475. Accordingly, the additional reporting requirement recommended by the PFD is not necessary.

### B. Distribution System Planning and Analysis

The PFD recommended that the Company present distribution costs in a manner that allows those costs to be trackable between any submitted DSP and a rate case using that DSP, including an exhibit that provides a walkthrough of variations in programs, subprograms, and categories. PFD, page 913. The PFD also recommended that "the Commission order that any costs in future cases that cannot be reconciled or tracked between the planning efforts and the rate case be disallowed." *Id*.

In its July 10, 2025 Order in Case No. U-20147, the Commission adopted DSP filing guidelines to be used by utilities going forward. Those guidelines state that "DSP spending classifications (such as programs, subprograms, categories) shall be aligned with such classification within the utility's rate case, with variations explained in detail." Case No. U-20147, July 10, 2025 Order, Exhibit A, page 3. The Company understands the PFD's recommendation to make costs and programs trackable between the DSP and the rate case as an implementation of

this Commission requirement in Case No. U-20147, and does not except to that part of the recommendation.

The Commission should reject the recommendation to determine in this case that future costs "that cannot be reconciled or tracked" should be disallowed. Whether distribution cost projections are approved in future cases should be based on the evidence presented in those cases, and the Commission should not predetermine that a failure to "reconcile or track" those costs will result in an automatic disallowance. While parties are free to argue for such a disallowance in future cases, making that predetermination in this case will only lead to future arguments as to whether the Company has sufficiently "reconciled or tracked" costs to permit their recovery. But an inability to "reconcile or track" the costs should not lead to an automatic disallowance when there may be situations where such costs are nonetheless reasonable and prudent and supported by the evidence in the case. Accordingly, the Commission should decline to adopt the recommendation to predetermine the reasonableness and prudence of future distribution costs without fully considering the future evidence that may support those costs.

The PFD also recommended that the Commission "(1) direct the Company to demonstrate a clear link between investments and quantifiable reliability improvements; and (2) assess cost-effectiveness, affordability, and potential rate impact of any SAIDI performance forecasts related to the U-21305 order – to include the extended glidepath options." PFD, pages 913-914. Similarly, the PFD recommended that the Company compare actual reliability performance to reliability projects and include a rate impact analysis for meeting reliability goals in five, seven, and 10-year timeframes. PFD, page 915. It is unclear what additional analysis the PFD is recommending, or whether there is anything more the Company should (or could) provide in response to this recommendation. The Company already identifies reliability improvements resulting from

distribution investments. See, for example, 3 TR 1166, 1172, 1314, 1398-1400, 1408, 1479-1484, 1938, 1940-1941, 1953. The Company also compares its modeled SAIDI performance to actual. See 3 TR 1401. And the Company provided projected costs and reliability improvements related to the Company's proposed reliability glidepath, as well as 7-year and 10-year glidepaths. See 3 TR 1412-1413. To the extent the PFD is recommending that the Commission require additional analysis that the Commission has not required as part of Case Nos. U-20147 and U-21305, the Commission should reject the recommendation and should instead continue to rely on the guidance given in those two proceedings related to distribution system analysis.

The PFD also recommended that the Commission find that "any expenses in future cases based *solely* on avoiding financial penalties or gaining a financial incentive set by the Commission are imprudent." PFD, page 915 (emphasis in original). Again, the Commission should reject this recommendation because it is a determination that the Commission does not need to make in this proceeding. There is no evidence that the Company proposed expenditures "solely" to avoid financial penalties or gain a financial incentive. And considering the Performance Based Regulation ("PBR") framework in a rate case is appropriate because it is at least a partial guide for the Company to target reliability improvements. See 3 TR 1572. The Commission-approved PBR framework establishes target reliability metrics with financial consequences for failing to meet those targets. *Id*. Under Michigan law, the Commission must establish electric utility rates based on the utility's cost of service. See MCL 460.11; see also *Gen Tel Co of Mich v Michigan Pub Serv Comm*, 341 Mich 620; 67 NW2d 882 (1954). It would be wholly unreasonable and unfair to deny the Company funding needed to meet reliability targets and then impose financial penalties for failing to meet those targets.

## C. Accounting Requests

The PFD recommended approval of Consumers Energy's request to defer $22.238 million in line clearing expense as a regulatory asset. PFD, page 1006. But the PFD also recommended that the Commission approve the short-term debt rate as the rate of return for the regulatory asset until the costs are securitized, noting that the Commission also approved the short-term debt rate for DTE Electric's tree-trimming surge. PFD, pages 1006-1007. The short-term debt rate is not the appropriate rate of return when considering the details of Consumers Energy's proposal and the evidence presented in this case.

The Company's proposal to securitize the line clearing regulatory asset when it reaches an appropriate balance is conditional upon receiving a return on the deferred expenses at the Company's prevailing weighted average cost of capital ("pre-tax WACC") during the ramp-up period until securitization takes place. 3 TR 1071. Due to the long-term nature of the deferred expense, the Company intends to fund this ramp-up with a mix of long-term debt and equity consistent with the Company's approved capital structure. 3 TR 857. Thus, the appropriate interest rate to be applied to the regulatory asset during the ramp-up is the Company's prevailing pre-tax WACC. *Id*.

Since the regulatory asset will not be short term, the Company cannot finance the regulatory asset with debt because it would add strain to the Company's credit metrics and would not match the financing costs with the return the Company earns on the regulatory asset. 3 TR 857. The application of a pre-tax WACC on this regulatory asset is particularly important because during the deferral period, the Company will be absorbing the cash and expense burden to fund the ramp up, but will not be collecting any of those costs from customers. *Id*. If the regulatory asset were funded with short-term debt instead of the pre-tax WACC, the Company's FFO would

be lower and its debt higher, resulting in a wholly insufficient standalone FFO-to-debt ratio of approximately 5%. 3 TR 858-859. The short-term debt rate is not acceptable for the deferred ramp-up regulatory asset due to these harmful credit metric impacts. 3 TR 859.

The Commission should not require a short-term debt rate for Consumers Energy just because the Commission approved a short-term debt rate for DTE Electric. In the Commission's May 2, 2019 Order in Case No. U-20162 ("U-20162 Order"), the Commission approved DTE Electric's proposal to defer line clearing surge expenses for later securitization at the short-term debt cost rate. U-20162 Order, page 80. In Case No. U-20162, the Commission found that the short-term debt rate was appropriate because it "is expected to be temporary given the company's plans to file for securitization of the tree trimming regulatory asset." *Id*. The Commission noted that DTE Electric had indicated that securitization of the regulatory asset is expected to occur every other year starting in 2020, and that DTE Electric was already intending to evaluate securitization of the remaining net book value of the Tier 2 plants pursuant to a settlement agreement in a depreciation case. *Id*. at pages 76, 80, note 8.

Just as the Commission relied on the circumstances in Case No. U-20162 in approving a short-term debt rate for DTE Electric, the Commission should also examine the individual facts and circumstances of this case for the appropriate rate of return to apply to Consumers Energy's request. As discussed, in this case use of a short-term debt rate is not reasonable due to the long-term nature of the deferred expense and the resulting strain to the Company's credit metrics. In addition, there has been a material change in the Company's risk environment that should be considered in determining the appropriate interest rate to apply to the Company's proposed ramp up, particularly the current volatility and uncertainty in financial markets, interest rates, and geopolitical tensions. 3 TR 865.

The cash flow and credit metric impact of the Company's several cost deferral mechanisms must also be considered as the Company continues to fund more customer investment prior to customer collections. 3 TR 865. This deferral increases long-term financing needs for the Company without creating cash flow the way traditional capital does through non-cash depreciation expense in rates, which further supports the Company's application of a pre-tax WACC on this particular regulatory asset balance. 3 TR 865-866. For all of these reasons, a short-term debt rate is not an acceptable financing assumption for the deferred regulatory asset associated with the line clearing ramp up. 3 TR 866. The Commission should not order this mismatch of financing costs with the return on the regulatory asset, and should instead approve a return on the deferred expenses at the Company's pre-tax WACC during the ramp-up period until securitization takes place.

## VII. CONCLUSION

For the reasons set forth in these Exceptions, Consumers Energy Company's briefing, and the evidentiary record in this matter, Consumers Energy Company requests that the Michigan Public Service Commission authorize Consumers Energy to adjust its retail electric rates so as to provide additional revenue of $422.8 million annually above levels established in Case No. U-21585 based on a projected 12-month test year ending April 30, 2027, plus an additional $24.3 million for the distribution deferral, and to grant other relief consistent with the positions set forth in Consumers Energy Company's Exceptions, Initial Brief, and Reply Brief.

Respectfully submitted,

CONSUMERS ENERGY COMPANY

Dated: February 17, 2026

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# ATTACHMENT A

January 30, 2026 | 09:05 ET~

# CMS Energy

| CMS-NYSE | Rating | Price: Jan-29 | Target ↓ | Total Rtn |
|---|---|---|---|---|
| | Outperform | $70.90 | $79.00 | 14% |

## Eight Is NOT The Magic Number - Negative Headline in CMS Electric PD

### Bottom Line:

**Yesterday the ALJ's PFD in CMS' electric rate case significantly broke rank from the state's historically gradual ratemaking approach, proposing an 8.2% ROE (implied ~$164mm revenue requirement/~39% of requested).** Although the proposed 50% equity layer was in line, many discrete details are unavailable until appendices/exhibits are filed by 2/6. **Despite historical improvement from ALJ PFDs, the headline will likely weigh on Michigan utilities until the case is adjudicated. We reduce our segment premium modestly despite our view the ALJ's position as likely driven by the political "affordability" narrative. Maintain Outperform.**

### Key Points

**Both CMS and DTE underperformed down 1.1% and 1.4%, respectively (adjusted for the XLU's IPP component) following the filing.** As mentioned, most critically the ALJ recommended the commission adopt an 8.2% ROE down over 170bp below CMS' currently authorized 9.90% ROE: this value is only 9bps above the lowest recommendation submitted by all intervenors. **Below we provide an overview of the ALJ PFD as understood at present; CMS estimates that a 9.90% ROE applied to the same parameters would equate to a ~$330mm revenue requirement:**

**Exhibit 1 - Consumers' Electric Rate Case Overview (Case U-21870)**

| | CMS Request | Staff Rec. | Chg. Vs. Staff | ALJ PD | ALJ Vs. CMS | ALJ Vs. Staff |
|---|---|---|---|---|---|---|
| **Date** | | **12/5/2025** | | **1/29/2026** | | |
| Rate Base (US$BN) | $16.4 | $16.3 | ($0.1) | $16.3 | ($0.1) | $0.0 |
| Return on Equity (ROE) | 10.25% | 9.75% | (0.50%) | 8.20% | (2.05%) | (1.55%) |
| Equity Layer | 50.75% | 50.0% | (0.75%) | 50.00% | (0.75%) | 0.00% |
| Rate of Return | 6.35% | 6.06% | (0.29%) | TBD | NA | NA |
| **Rate Relief ($USMM)** | **$423** | **$323** | | **$164** | **($259)** | **($159)** |
| ***Delta*** | | ***($100)*** | | ***($259)*** | | |
| ***% of Company's Request*** | | ***76%*** | | ***39%*** | | |

Source: BMO Capital Markets, Company Reports

While the sharp 155bps decline (or (-17%) vs. Staff is concerning, we expect the MPSC to moderate the final outcome based on MPSC Chair Scripps' commentary in the company's most recently completed gas rate case supporting more modest year-over-year adjustments. **However, we reduce our Consumers Energy earnings premium to 10% from 15%, reducing our Target Price to $79 from $81.** *See inside for additional context on the order as understood today.*

| Key Changes | |
|---|---|
| | Target |
| | $79.00↓ |
| | $81.00 |

For disclosure statements, including the Analyst Certification, please refer to page(s) 4 to 8.

IN Fact

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| Company Data | | | in $ |
|---|---|---|---|
| Dividend | $2.17 | Shares O/S (mm) | 304.3 |
| Yield | 3.1% | Market Cap (mm) | $21,576 |
| P/BV | 2.4x | Net Debt (mm) | $16,351 |

| BMO Estimates | | | | in $ |
|---|---|---|---|---|
| (FY-Dec.) | 2024A | 2025E | 2026E | 2027E |
| EPS | $3.34 | $3.59 | $3.87 | $4.16 |
| DPS | $2.06 | $2.17 | $2.29 | $2.41 |

| Consensus Estimates | | | | |
|---|---|---|---|---|
| | 2024A | 2025E | 2026E | 2027E |
| EPS | | $3.59 | $3.85 | $4.16 |

| Valuation | | | | |
|---|---|---|---|---|
| | 2024A | 2025E | 2026E | 2027E |
| P/E | 21.2x | 19.7x | 18.3x | 17.0x |
| Div. Yield (%) | 2.9% | 3.1% | 3.2% | 3.4% |

| QTR. EPS | Q1 | Q2 | Q3 | Q4 |
|---|---|---|---|---|
| 2024A | $0.97 | $0.66 | $0.84 | $0.87 |
| 2025E | $1.02a | $0.71a | $0.93a | $0.93 |
| 2026E | $1.00 | $0.85 | $0.87 | $1.16 |
| 2027E | $1.07 | $0.91 | $0.93 | $1.25 |

## Our Thesis

Our positive outlook reflects the company's above-average EPS and DPS growth rates, long-dated visible capital program, consistent execution, and supportive regulatory environment, which can now be owned at a discount to its historical relative valuation.

BMO Capital Markets

CMS Energy - Block Summary Model

| Income Statement | 2024A | 2025E | 2026E | 2027E |
|---|---|---|---|---|
| Consumers Energy | 1,514 | 1,779 | 1,990 | 2,241 |
| Enterprises, EnerBank, & Parent | (27) | (54) | (66) | (78) |
| Consolidated EBIT | 1,487 | 1,725 | 1,925 | 2,162 |
| Depreciation & Amortization | 1,240 | 1,328 | 1,430 | 1,542 |
| EBITDA | 3,077 | 3,387 | 3,711 | 4,083 |
| Interest Expense | 726 | 864 | 966 | 1,092 |
| Income Tax | 177 | 181 | 202 | 222 |
| Income from continuing operations | 998 | 1,075 | 1,176 | 1,291 |
| Weighted Average Shares Outstanding | 298 | 299 | 304 | 310 |
| Diluted Operating EPS | $3.34 | $3.59 | $3.87 | $4.16 |
| Dividends per Share | $2.06 | $2.17 | $2.29 | $2.41 |
| **Cash Flow Statement** | **2024A** | **2025E** | **2026E** | **2027E** |
| Operating Cash Flow | 2,370 | 2,451 | 2,782 | 2,998 |
| Investing Cash Flow | (3,039) | (4,316) | (4,417) | (5,118) |
| Financing Cash Flow | 614 | 1,860 | 1,650 | 2,042 |
| Net Change in Cash Flow | (55) | (4) | 16 | (78) |
| EOP Cash on Balance Sheet | 193 | 189 | 205 | 127 |
| Common stock (net) | (28) | 0 | 500 | 500 |
| Net debt issued/(repaid) | 1,010 | 2,510 | 1,845 | 2,290 |
| Dividends paid | (626) | (650) | (695) | (748) |
| **Balance Sheet** | **2024A** | **2025E** | **2026E** | **2027E** |
| Common Equity | 8,230 | 8,656 | 9,637 | 10,679 |
| Preferred Equity | 224 | 0 | 224 | 224 |
| Total Debt | 16,454 | 18,979 | 20,824 | 23,114 |
| Enterprise Value | $35,967 | $38,405 | $40,663 | $43,438 |
| Common equity % | 34.7% | 32.6% | 32.8% | 32.6% |
| Total Debt % | 65.3% | 67.4% | 67.2% | 67.4% |
| Book Value per Share | $29.33 | $30.63 | $33.45 | $36.13 |

Source: BMO Capital Markets, Company Reports

Scenarios

## Valuation

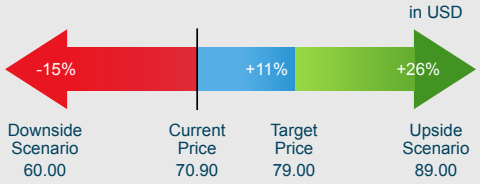
Our target price is arrived at using a sum-of-the-parts methodology. Our framework begins with the relevant sector average P/E multiple using 2027E EPS as a base, which we then adjust (premium, discount, or no change) to reflect the relative fundamentals of that segment.

## Upside Scenario $89.00

Our upside scenario reflects continued multiple expansion associated with the company's premium, visible, above-average earnings growth, as well as higher capacity pricing at DIG.

## Downside Scenario $60.00

Our downside scenario reflects tightening monetary policy, a deceleration of the company's rate base growth, and risks to the global macro environment.




## Key Catalysts

Continued execution against guidance. Working to achieve positive outcomes in the ongoing electric rate case after settling multiple regulatory proceedings in the year prior.

## Company Description

CMS Energy's principal subsidiary is Consumers Energy, an integrated electric/gas utility serving about 6.6 million customers in Michigan. The Enterprises segment engages in independent power production, marketing of independent power production, and the development and operation of renewable generation.

CMS-NYSE Research
Glossary
Company Models

BMO Capital Markets

## Reviewing the Regulatory Environment in Michigan

As part of CMS' most recently completed gas rate case, MPSC Chair Dan Scripps noted that "in balancing… …competing evidentiary points that we found a modest decrease in the ROE was appropriate, but not as much as recommended by staff, the Attorney General and other parties and ultimately recommended by the administrative law judge". **Given the 10bps reduction in the associated final order, we do expect a more moderate outcome when the MPSC reviews all data points before its final order.**

However, while we are not adjusting our earnings outlook as a result of this decision, **with the upcoming gubernatorial election and heightened focus on utility operations in light of growing data center projects we reduce the 15% premium we apply to Consumers Energy's earnings to 10%.** After refreshing MTM, this reduction moves our TP to $79 from $81. **We expect regulatory activity in the state to garner additional scrutiny, making the company's upcoming IRP filing and its implications for long-term capital investment a key event ahead.**

**Exhibit 2 - CMS SOTP Valuation**

| | | | | | | | | BMO Low Case | | BMO Base Case | | BMO High Case | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Regulated, Parent & Other | Valuation Metric | 2028E EPS | Sector Comp | Sector Multiple | Prem/ (Discount) | Base Multiple | P/E Multiple | Implied Value ($ MM) | P/E Multiple | Implied Value ($ MM) | P/E Multiple | Implied Value ($ MM) |
| Consumers Energy | EPS | $5.03 | Blend | 16.0x | +10.0% | 17.6x | 14.1x | $71 | 17.6x | $88 | 19.6x | $99 |
| NorthStar | EPS | $0.25 | | 16.0x | +0.0% | 16.0x | 12.5x | $3 | 16.0x | $4 | 18.0x | $4 |
| Parent & Other | EPS | ($0.77) | Blend | 16.0x | +0.0% | 17.5x | 17.5x | ($14) | 17.5x | ($14) | 17.5x | ($14) |
| **Utility & Parent Value** | | **$4.50** | | | | | **13.4x** | **$60** | **17.5x** | **$79** | **19.9x** | **$89** |
| Upside/(Downside) | | | | | | | | (14.7%) | | 11.3% | | 26.2% |
| Current Yield | | | | | | | | 3.2% | | 3.2% | | 3.2% |
| **Total Return** | | | | | | | | **(11%)** | | **15%** | | **29%** |

Source: BMO Capital Markets, Company Reports

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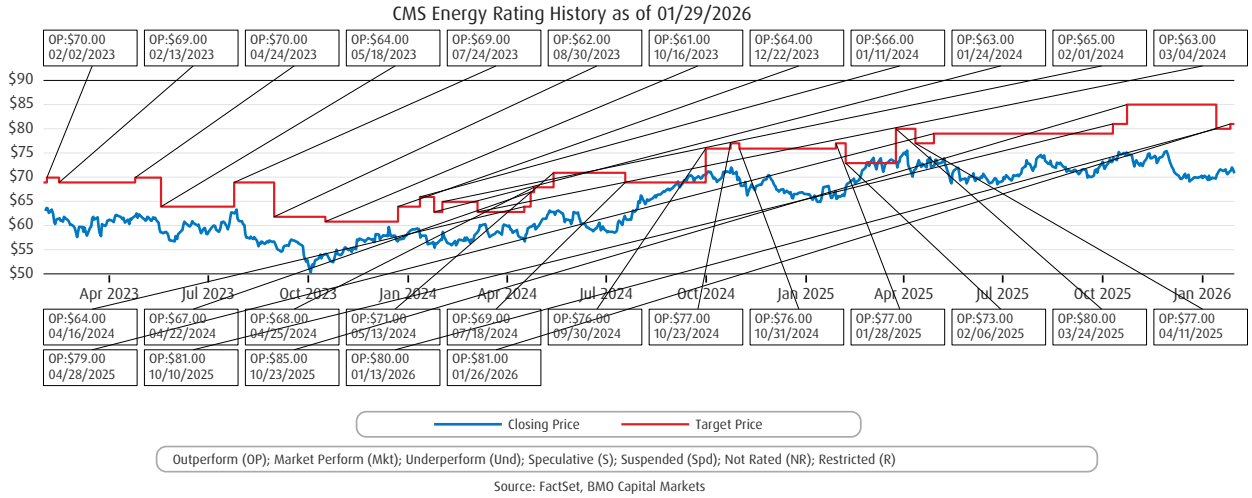
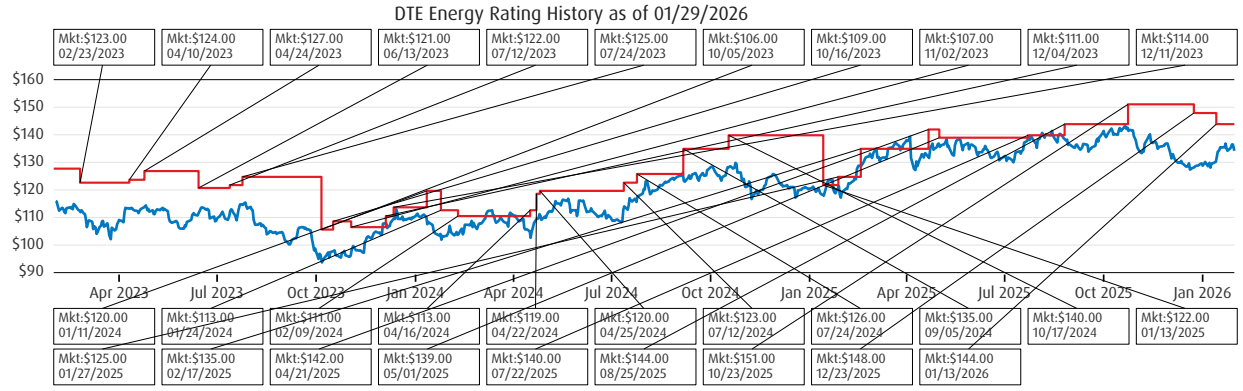



Source: FactSet, BMO Capital Markets




Source: FactSet, BMO Capital Markets

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**Methodology:** Our target price uses a sum-of-the-parts methodology that we apply to our diversified utility group. It utilizes P/E and/or public market valuation methodologies.

**Risks:** CMS's regulated profile exposes the company to business risk including but not limited to federal and state regulatory risk, federal and state political risk, environmental policy, interest rate risk, access to capital markets, construction risk, changes in customer demand trends, changes in customer affordability, extreme weather, natural disaster, and equipment failure.

**Methodology and Risks to Target Price/Valuation for DTE Energy (DTE-NYSE)**

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|---|---|---|---|---|---|---|---|
| Buy | Outperform | 55.4 % | 23.4 % | 57.7 % | 59.4 % | 67.6 % | 57.7% |
| Hold | Market Perform | 42.4 % | 22.4 % | 42.3 % | 39.3 % | 32.4 % | 37.5% |
| Sell | Underperform | 2.2 % | 0.0 % | 0.0 % | 1.3 % | 0.0 % | 4.8% |

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# ATTACHMENT B

Jefferies

NORTH AMERICA | Power & Utilities

CMS Energy

Equity Research
January 30, 2026

# Michigan Rates: ALJ Goes Low, History Says Otherwise. Bumpier Path Ahead?

The ALJ's 8.2% ROE recommendation in CMS's U-21870 electric rate case sits 155bps below Staff's 9.75% and 170bps below the 9.89% average Michigan has authorized across nine utility cases since 2023. With the Commission's final order expected by April 2, 2026, and appendices due Feb. 6th, the PFD represents a non-binding recommendation that probability-weighted outcomes should discount materially.

**The ALJ's 8.2% ROE is an outlier that conflicts with Michigan's established regulatory track record: negative update.** On January 29, the Administrative Law Judge (ALJ) filed an amended Proposal for Decision (PFD) in Consumer Energy (CMS Energy [CMS] subsidiary) rate case recommending an **8.2% ROE** with a 50/50 capital structure (U-21870). This is -155bps below the Michigan Public Service Commission's (PSC) Staff's 9.75% from Dec 5 and the 9.5% from the ALJ in the prior case. 8.2% is a stark departure from Michigan's recent authorized returns of ~9.89% across nine utility proceedings since 2023 and is one of the lowest data points nationally. CMS is currently authorized 9.90% ROE electric (U-21585, March 2025) and 9.80% natural gas (U-21806, September 2025). *The 8.2% ALJ is the lowest ROE recommendation in recent memory and is a clear negative development. We still expect the PSC to authorize a high 9% ROE but the volatility and uncertainty is fraying investor confidence in Michigan as a premium jurisdiction.*

**ROE drives the gap between Staff and ALJ revenue requirements.** Staff's Dec 5th brief supported a total revenue deficiency of ~$317m, while the ALJ's 8.2% ROE would translate to a revenue increase closer to $164m. The ~$150m delta is largely explained by the 155bps ROE differential applied against a ~$16b effective rate base. CMS' original June 2025 filing requested $460m (including a $24m distribution deferral surcharge) with a 10.25% ROE request. CMS revised the ask to $447m in October 2025.

**The amended PFD removed an internally inconsistent numerical summary, but left the detailed math for a Feb. 6th update.** The ALJ issued both an original ***and*** amended PFD on Jan 29th, as the original PFD's conclusion page was erroneous copied from the Jan 2025 filing (9.5% ROE and $109m revenue deficiency). The amended version removed this reference entirely. The ALJ's supporting appendices, expected February 6th, will provide detailed revenue requirement workpapers with actual dollar figures.

**Michigan precedent and procedural reality favor a more constructive final order.** The PFD is a non-binding recommendation. The three-member Commission issues the final order, expected by **April 2**. Michigan operates with appointed Commissioners and a regulatory framework that has consistently delivered constructive outcomes for utilities, including forward-looking test years, 10-month rate case timelines, and ROEs that track above national averages. *DTE/CMS were down -1.3% following the PFD filing suggests investors are probability-weighting the likelihood that the Commission moderates the ALJ's ROE recommendation toward recent precedent. The path from PFD to final order includes an exceptions and reply brief process that will allow all parties to challenge the ALJ's analysis.*

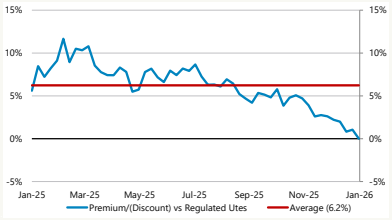
**The timeline from here centers on the Feb. 6th appendices and April final order.** Parties will file exceptions to the PFD (Feb 17) and subsequent reply briefs (Feb 26) before the Commission deliberates. The Feb 6th appendix filing will provide the first complete numerical picture of the ALJ's recommended revenue requirement. The Commission's final order by April 2, 2026, will

**FLASH NOTE**

| | |
|---|---|
| RATING | **BUY** |
| PRICE | **$70.90^** |
| PRICE TARGET \| % TO PT | **$81.00 \| +14%** |
| 52W HIGH-LOW | **$76.45 - $65.17** |
| FLOAT (%) \| ADV MM (USD) | **98.7% \| 189.81** |
| MARKET CAP | **$21.7B** |
| TICKER | **CMS** |

^Prior trading day's closing price unless otherwise noted.

**Exhibit 1 - CMS' relative premium/(discount) vs. regulated electric peers on an FY2 P/E basis.**




Source: Jefferies LLC, Bloomberg.

*While we note that an 8.2% electric ROE would lower CMS' earnings power by ~$0.39/ share (all else equal), we expect a reasonable outcome in this case, and continue to model a high 9% ROE going forward, consistent with our recent conversations with stakeholders and experts.*

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determine the authorized ROE, capital structure, rate base, and revenue requirement that governs rates through the test year ending April 30, 2027.

Exhibit 2 - CMS mini-financials

| Income Statement ($Mn) | 2025E | 2026E | 2027E | 2028E | 2029E | 2030E |
|---|---|---|---|---|---|---|
| **Total Operating Revenues** | **8,176** | **8,517** | **8,945** | **9,283** | **9,728** | **10,149** |
| Supply costs | 2,943 | 2,955 | 2,967 | 2,981 | 2,993 | 3,005 |
| O&M | 1,630 | 1,617 | 1,655 | 1,648 | 1,687 | 1,648 |
| Depreciation & amortization | 1,341 | 1,448 | 1,568 | 1,677 | 1,789 | 1,925 |
| Taxes, other than net income (TOTI) | 509 | 538 | 559 | 581 | 607 | 633 |
| **Operating Income** | **1,753** | **1,959** | **2,195** | **2,396** | **2,652** | **2,937** |
| Other Income (Expense) | 47 | 47 | 50 | 50 | 53 | 58 |
| Non-operating retirement benefits, net | 163 | 160 | 161 | 160 | 161 | 161 |
| Interest Expense | 785 | 876 | 985 | 1,071 | 1,144 | 1,244 |
| Income Before Income Taxes | 1,179 | 1,290 | 1,421 | 1,536 | 1,722 | 1,912 |
| Income Taxes | 144 | 155 | 165 | 154 | 191 | 250 |
| Preferred Dividends | 12 | 12 | 12 | 12 | 12 | 12 |
| Non-controlling Interest | (56) | (56) | (56) | (56) | (56) | (56) |
| **Adjusted Net Income** | **1,079** | **1,179** | **1,301** | **1,426** | **1,574** | **1,705** |

| Cash Flows ($Mn) | 2025E | 2026E | 2027E | 2028E | 2029E | 2030E |
|---|---|---|---|---|---|---|
| Net Income | 1,065 | 1,179 | 1,301 | 1,426 | 1,574 | 1,705 |
| Depreciation | 1,341 | 1,448 | 1,568 | 1,677 | 1,789 | 1,925 |
| Deferred income taxes and tax credits, net | 214 | 228 | 252 | 271 | 299 | 353 |
| Other | (10) | 11 | (4) | 5 | (2) | (4) |
| **CFFO** | **2,610** | **2,866** | **3,117** | **3,378** | **3,660** | **3,979** |
| CapEx | (4,300) | (4,400) | (5,100) | (4,600) | (4,750) | (5,550) |
| Other | (148) | (151) | (149) | (150) | (150) | (150) |
| **CFFI** | **(4,448)** | **(4,551)** | **(5,249)** | **(4,750)** | **(4,900)** | **(5,700)** |
| Change in long-term debt, net | 1,970 | 1,960 | 2,465 | 1,745 | 1,695 | 2,240 |
| Common Dividends Paid | (652) | (701) | (757) | (821) | (890) | (964) |
| Issuance of Common Stock | 500 | 450 | 450 | 450 | 450 | 450 |
| Other Financing Activities | (15) | (12) | (14) | (13) | (13) | (13) |
| **CFFF** | **1,803** | **1,697** | **2,144** | **1,361** | **1,242** | **1,713** |
| Change in cash, net | (34) | 12 | 12 | (11) | 2 | (8) |

| Balance Sheet ($Mn) | 2025E | 2026E | 2027E | 2028E | 2029E | 2030E |
|---|---|---|---|---|---|---|
| Cash and cash equivalents | 69 | 81 | 93 | 82 | 85 | 77 |
| Regulated utility plant, net | 28,322 | 31,274 | 34,806 | 37,729 | 40,690 | 44,315 |
| Construction work in progress (CWIP) | 2,109 | 2,121 | 2,134 | 2,146 | 2,159 | 2,174 |
| Regulatory assets | 3,569 | 3,569 | 3,569 | 3,569 | 3,569 | 3,569 |
| Pension and other postretirement benefits | 1,627 | 1,627 | 1,627 | 1,627 | 1,627 | 1,627 |
| Other | 3,196 | 3,206 | 3,231 | 3,250 | 3,273 | 3,296 |
| **Total Assets** | **38,892** | **41,878** | **45,461** | **48,404** | **51,403** | **55,059** |
| Long-term debt | 18,359 | 20,319 | 22,784 | 24,529 | 26,224 | 28,464 |
| Deferred income taxes | 3,139 | 3,368 | 3,620 | 3,891 | 4,189 | 4,542 |
| Regulatory liabilities | 4,067 | 4,067 | 4,067 | 4,067 | 4,067 | 4,067 |
| Other | 3,889 | 3,760 | 3,631 | 3,504 | 3,375 | 3,247 |
| **Total Shareholder's Equity** | **9,437** | **10,365** | **11,358** | **12,413** | **13,547** | **14,738** |
| **Total Liabilities and Equity** | **38,892** | **41,878** | **45,461** | **48,404** | **51,403** | **55,059** |

Source: Jefferies LLC, company materials.

## Company Description

**CMS Energy**

CMS Energy is a public utility holding company with regulated utility operations concentrated in the Michigan United States. The Company primarily owns regulated electric and gas utilities with distribution, transmission, and generation assets. The Company generates electricity from coal, natural gas, and renewables. The Company has select unregulated operations.

## Company Valuation/Risks

**CMS Energy**

PT based on SOTP using 2030E EBITDA for DIG/Peakers and 2028E EPS for all else. Risks to achievement of the Price Target and Rating include 1) regulatory, state/Federal administrative, legislative, judicial, tax, environmental, and political actions; 2) prudency of regulatory actions & investments; 3) ability to earn the target regulatory authorized return on equity; 4) capital markets, equity, & rating agency requirements and access; 5) changes to the capital expenditure forecasts; 6) volatility in interest rates and pension returns; 7) changes in commodity prices; 8) natural disasters, wildfires, weather, & public health crises; 9) military actions and terrorism; 10) construction of capital projects; 11) changes in electric and natural gas volumes; 12) labor agreements and turnover of key executives; 13) cyber incidents; 14) supply chain disruptions; 15) merger and acquisition activity, 16) counterparty performance, and 17) access to insurance.

**DTE Energy Co**

We value DTE using a 2028 sum-of-the-parts methodology. Risks to achievement of the price target and rating include: 1) regulatory, state/Federal administrative, legislative, judicial, tax, environmental, and political actions; 2) prudency of regulatory actions & investments; 3) ability to earn the target regulatory authorized return on equity; 4) capital markets, equity, & rating agency requirements and access; 5) changes to the capital expenditure forecasts; 6) volatility in interest rates and pension returns; 7) changes in commodity prices; 8) nuclear events, natural disasters, wildfires, weather, & public health crises; 9) military actions and terrorism; 10) construction of capital projects; 11) changes in electric volumes; 12) labor agreements and turnover of key executives; 13) cyber incidents; 14) supply chain disruptions; 15) merger and acquisition activity, 16) counterparty performance, and 17) access to insurance.

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## Investment Recommendation Record

**(Article 3(1)e and Article 7 of MAR)**

| | |
|---|---|
| Recommendation Published | January 30, 2026 9:08 A.M. |
| Recommendation Distributed | January 30, 2026 9:08 A.M. |

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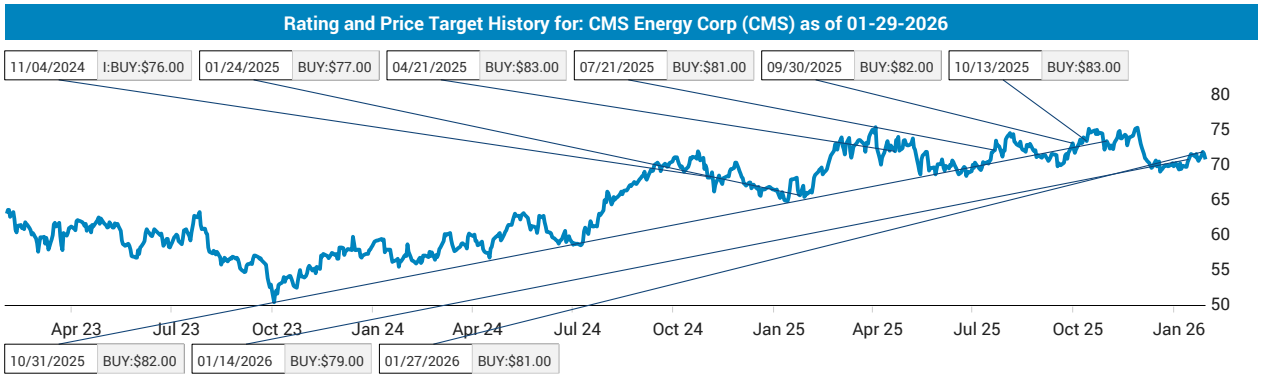
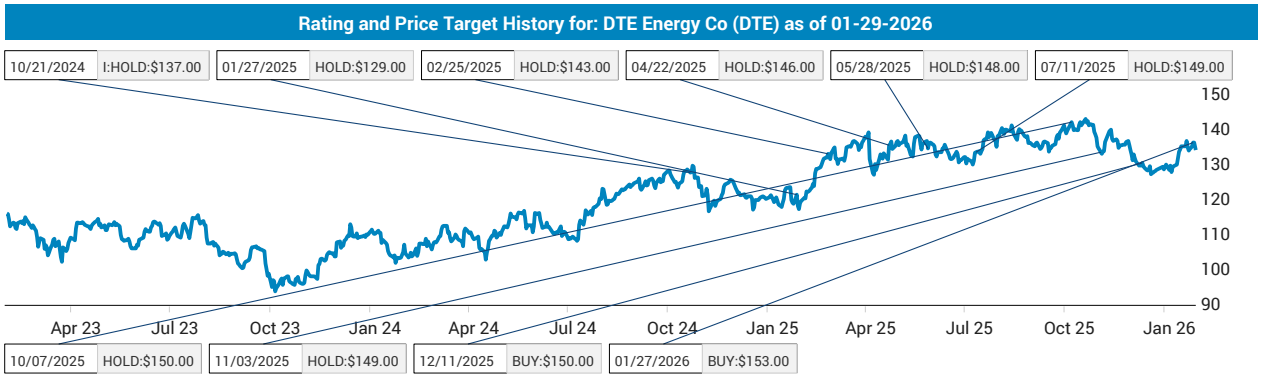
## Other Companies Mentioned in This Report

- CMS Energy Corp (CMS: $70.90, BUY)

• DTE Energy Co (DTE: $134.44, BUY)

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Legend:

I: Initiating Coverage

D: Dropped Coverage

B: Buy

H: Hold

UP: Underperform

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| | | | IB Serv./Past12 Mos. | | JIL Mkt Serv./Past12 Mos. | |
|---|---|---|---|---|---|---|
| | Count | Percent | Count | Percent | Count | Percent |
| BUY | 2166 | 61.19% | 368 | 16.99% | 112 | 5.17% |
| HOLD | 1210 | 34.18% | 108 | 8.93% | 15 | 1.24% |
| UNDERPERFORM | 164 | 4.63% | 2 | 1.22% | 2 | 1.22% |

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# ATTACHMENT C

# STATE OF MICHIGAN

# COURT OF APPEALS

| | |
|---|---|
| WHISPERING PINES GOLF CLUB, LLC,<br><br>Petitioner-Appellant, | UNPUBLISHED<br>August 21, 2007 |
| v | No. 269118<br>Tax Tribunal |
| TOWNSHIP OF HAMBURG,<br><br>Respondent-Appellee. | LC No. 00-259437 |

Before: Whitbeck, C.J., and Talbot and Zahra, JJ.

PER CURIAM.

Petitioner Whispering Pines Golf Club, LLC, appeals as of right from the judgment of the Michigan Tax Tribunal establishing the true cash value, assessed value, and taxable value of the real property in issue for the 1998 and 1999 tax years. This tax appeal is before this Court for a third time.[1] We affirm.

## I. Basic Facts And Procedural History

The property in issue is an eighteen-hole golf course owned by Whispering Pines and located in Hamburg Township. The Tax Tribunal applied the income approach for purposes of establishing the true cash value, assessed value, and taxable value of real property in issue. To that end, the annual income of the property for purposes of the tax years in issue is based, in part, on the approximate number of eighteen-hole golf rounds played per year.

At the onset of this litigation, the Tax Tribunal accepted Hamburg Township's appraiser's conclusion that 31,500 rounds could be played annually, with 60 percent of those rounds played on the weekend and 40 percent played on the weekday, which was the appraiser's rough estimate based on similar golf courses in the area. Therefore, Whispering Pines could have been expected to play 18,900 weekend rounds and 12,600 weekday rounds.

[1] See *Whispering Pines Golf Club LLC v Hamburg Twp*, unpublished opinion per curiam of the Court of Appeals, issued September 16, 2003 (Docket No. 233218) (*Whispering Pines I*), and *Whispering Pines Golf Club LLC v Hamburg Twp*, unpublished opinion per curiam of the Court of Appeals, issued September 22, 2005 (Docket No. 254672) (*Whispering Pines II*).

In *Whispering Pines I*, a panel of this Court found it to be mathematically impossible to play 18,900 weekend rounds and directed the tribunal, on remand, to recalculate the number of weekend rounds, further noting that the estimates also failed to account for inclement weather.[2] On remand, the tribunal calculated 11,520 weekend rounds based on a foursome teeing off every ten minutes for an average of eight hours each day, equaling 384 players per weekend. This calculation was based on 30 weekends per year, the expected golf season. However, the tribunal again accepted the original estimate of 31,500 rounds per year, which, in turn, caused it to raise the number of weekday rounds to 19,980.

In *Whispering Pines II*, a panel of this Court concluded that the tribunal erred by failing to apply the ratio provided by the Hamburg Township's appraiser and by recalculating the number of weekday rounds because the remand order in *Whispering Pines I* did not allow the tribunal to recalculate those rounds.[3] The panel noted, however, that the ratio could be altered based on Hamburg Township's appraiser's admission that her ratio might be off.[4] On second remand, the tribunal found the total number of rounds to be 28,440, with 15,840 weekend rounds and 12,600 weekday rounds, which equated to ratio of 56/44 percent.

## II. Law Of The Case

Whispering Pines contends that the tribunal erred by failing to comply with the law of the case doctrine, claiming that this Court in *Whispering Pines II* affirmed the number of weekend rounds at 11,520. To that end, it contends that the tribunal should have merely adjusted the final estimate of value according to that number. In *Grace v Grace*, this Court observed the following:

> The law of the case doctrine provides that if an appellate court has decided a legal issue and remanded the case for further proceedings, the legal issue determined by the appellate court will not be differently decided on a subsequent appeal in the same case where the facts remain materially the same. Therefore, generally, an appellate court's determination of an issue in a case binds lower tribunals on remand and the appellate court in subsequent appeals. The rationale behind the doctrine includes the need for finality of judgments and the lack of jurisdiction of an appellate court to modify its judgments except on rehearing. Further, the law of the case doctrine applies without regard to the correctness of the prior determination, so that a conclusion that a prior appellate decision was erroneous is not sufficient in itself to justify ignoring the law of the case doctrine.[5]

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[2] *Whispering Pines I*, *supra* at 9-10.

[3] *Whispering Pines II*, *supra* at 3-4.

[4] *Id.* at 4 n 2.

[5] *Grace v Grace*, 253 Mich App 357, 362-363; 655 NW2d 595 (2002) (internal citations omitted).

We conclude that Whispering Pines' argument is wholly without merit because this Court in *Whispering Pines II* expressly stated that the discussion in *Whispering Pines I* concerning 11,520 weekend golf rounds was "not a finding" and that the number of weekend golf rounds was for the tribunal to determine.[6]

Whispering Pines also argues that *Whispering Pines II* cannot be understood as allowing the tribunal to recalculate the number of weekend golf rounds because there is no express instruction permitting it to do so. Again, we conclude that Whispering Pines' argument is wholly without merit because this Court in *Whispering Pines II* made it abundantly clear that the tribunal was to fix the number of weekday rounds at 12,600 and was to recalculate the number of weekend rounds while considering the 40/60 ratio testified to by the appraiser.[7]

III. Competent, Material, and Substantial Evidence

Whispering Pines argues that the tribunal's factual findings concerning the number of weekend golf rounds were not supported by competent evidence. We disagree. When fraud is not claimed, the Tax Tribunal's decision is reviewed for misapplication of the law or adoption of a wrong principle.[8] The tribunal's factual findings are conclusive if they are supported by competent, material, and substantial evidence on the whole record.[9] "Substantial evidence is 'the amount of evidence that a reasonable mind would accept as sufficient to support a conclusion,' and it may be 'substantially less than a preponderance.'"[10]

The tribunal found that 15,840 weekend golf rounds could be played based on its finding that "(1) the golf season in Michigan consists of 30 weekends; (2) of the 30 weekends, 12 weekends would permit ten hours of golfing starts and 18 weekends would permit eight hours of golfing starts; and (3) 30 golfers tee off every hour on a weekend day." Whispering Pines challenges the second and third finding as unsupported by the evidence.

In calculating the number of hours played, the tribunal relied on Hamburg Township's appraiser's testimony that she believed foursomes went off every seven or eight minutes. And while Whispering Pines' counsel directed her to consider whether six or seven foursomes could be sent off per hour, this Court in *Whispering Pines I* acknowledged that she did not accept those assumptions as true.[11] Ultimately, the tribunal elected to adopt the rate of one foursome every eight minutes, which calculates to 7.5 foursomes, i.e., 30 players per hour. Accordingly, the

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[6] *Whispering Pines II, supra* at 4.

[7] *Id.* at 3-4.

[8] *Wexford Medical Group v City of Cadillac*, 474 Mich 192, 201; 713 NW2d 734 (2006).

[9] *Id.* at 201.

[10] *Inter Coop Council v Dep't of Treasury*, 257 Mich App 219, 221-222; 668 NW2d 181 (2003) (citation omitted).

[11] *Whispering Pines I, supra* at 10 n 31.

tribunal's second finding is conclusive because it was based on competent, material, and substantial evidence in the form of the appraiser's testimony.

In calculating the number of potential hours of golfing, the tribunal acknowledged the testimony of Hamburg Township's appraiser that it would take eight hours to send off 200 players in a day at a rate of 24 players per hour. However, the tribunal reconsidered the number of hours based on its understanding that there were many more hours in the day in which a person could golf in Michigan, which it felt was buttressed by testimony from a certified public accountant (CPA) about how "top notch" Michigan golf courses generally begin charging twilight fees at 6:30 p.m. The CPA also noted that Whispering Pines began charge twilight fees at 3:00 p.m. That Whispering Pines might begin charging twilight fees earlier in the day than "top notch" Michigan golf courses does not mean that the length of the golfing day is 3 hours shorter at the course in issue. Rather, testimony that twilight rates begin at some courses at 6:30 p.m. supports the tribunal's conclusion that, assuming a teeoff time between 7:00 a.m. and 7:30 a.m., the number of hours golfers could teeoff in Michigan "could be as high as eleven or twelve."

Additionally, the tribunal's adoption of average golfing hours below the potential number assuming no inclement weather adequately provides for the possibility that such weather could impact the number of rounds played.

Further, under § 77 of the Administrative Procedures Act,[12] "[a]n agency in a contested case may take official notice of judicially cognizable facts, and may take notice of general, technical or scientific facts within the agency's specialized knowledge."[13] A "cognizable fact" is a fact that is "capable of being perceived and known."[14] MRE 201(b) provides that "[a] judicially noticed fact must be one not subject to reasonable dispute in that it is either (1) generally known within the territorial jurisdiction of the trial court or (2) capable of accurate and ready determination by resort to sources whose accuracy cannot reasonably be questioned." Moreover, in addition to reviewing "the propriety of the judicial notice taken by" a lower tribunal, an appellate court "can even take judicial notice on their own initiative of facts not noticed below."[15]

The tribunal concluded that golf can be played in Michigan from April to October. It also adopted a 7:00 a.m. to 7:30 a.m. morning start time. It is "generally known" that the number of daylight hours increases from April to the summer solstice in June and decreases from the summer solstice to the winter solstice in December. In 2006, the year of decision, there were twelve full weekends from April 1 until the summer solstice, which was midweek. From the

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[12] MCL 24.271 *et seq*.

[13] MCL 24.277. See *Great Lakes Div of Nat'l Steel Corp v City of Ecorse*, 227 Mich App 379, 400-401; 576 NW2d 667 (1998).

[14] *Random House Webster's College Dictionary* (1997), p 255 (defining "cognizable").

[15] *People v Burt*, 89 Mich App 293, 297; 279 NW2d 299 (1979) (observing that such authority is, "at the very least," implied by MRE 201[c]).

summer solstice until the end of October 2006, there were nineteen full weekends. Further, the actual length of the period between sunrise and sunset can be "read[ily] determined by resort to sources whose accuracy cannot be questioned." On April 1, 2006 in Ann Arbor: morning twilight began at 5:49 a.m. and evening twilight ended at 7:29 p.m.; sunrise was at 6:18 a.m. and sunset was at 7:01 p.m.[16] On June 21, 2006, the times were as follows: morning twilight began at 5:24 a.m. and evening twilight ended at 9:50 p.m.; sunrise was at 5:58 a.m. and sunset was at 9:15 p.m.[17] On October 31, 2006, the times were as follows: morning twilight began at 6:38 a.m. and evening twilight ended at 5:59 p.m.; sunrise was at 7:07 a.m. and sunset was at 5:30 p.m.[18] Thus, for the entire postulated golf season in 2006, the sun had risen during the assumed morning start time, and the number of daylight hours was never below ten. On April 1 and June 21, the approximate number of hours between 7:00 a.m. and sunset were twelve and fourteen, respectively.

Clearly, an eighteen-hole round of golf could not be started and completed at *any* time during the daylight hours. For example, while a round of golf that was started at 9:14 p.m. on June 21, 2006 could have been played through the evening twilight illumination, the round could not have been continued once complete darkness fell thirty-five minutes later. However, a round could arguably have been played between 5:00 p.m. (ten hours after the 7:00 a.m. start time) and 9:50 p.m. Indeed, it is likely that a foursome could have begun later than 5:00 p.m. on June 21, 2006 and still have completed an eighteen-hole round of golf. Two golfers beginning even later than this hypothetical foursome could arguably have completed nine holes each before darkness fell, which as the tribunal noted is comparable to one eighteen-hole round of golf. It might be difficult for a foursome beginning at 5:00 p.m. on April 1, 2006 to complete the round before the sun set or by the end of evening twilight (approximately 2 and 2.5 hours, respectively). However, the expansion of the golfing day as the season approaches the summer solstice would balance out the shorter days early on in the season. This entire line of reasoning applies equally to the post-summer solstice portion of the season.

Accordingly, the tribunal's third finding is conclusive because it was based on competent, material, and substantial evidence.

Affirmed.

/s/ William C. Whitbeck
/s/ Michael J. Talbot
/s/ Brian K. Zahra

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[16] US Naval Observatory, Astronomical Applications Department, <http://www.usno.navy.mil/> (accessed August 20, 2007). No information was available on the cited website for Hamburg. However, Ann Arbor is only approximately fifteen miles from Hamburg.

[17] *Id*.

[18] *Id*.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for<br>the generation and distribution of<br>electricity and for other relief. | )<br>)<br>)<br>)<br>)<br>) | Case No. U-21870 |

**PROOF OF SERVICE**

STATE OF MICHIGAN )
) SS
COUNTY OF JACKSON )

Melissa K. Harris, being first duly sworn, deposes and says that she is employed in the Legal Department of Consumers Energy Company; that on February 17, 2026, she served an electronic copy of **Consumers Energy Company's Exceptions to the Proposal for Decision** upon the persons listed in Attachment 1 hereto, at the e-mail addresses listed therein.

Melissa K. Harris

Subscribed and sworn to before me this 17th day of February 2026.

Crystal L. Chacon
Crystal L. Chacon, Notary Public
State of Michigan, County of Eaton
My Commission Expires: 05/25/30
Acting in the County of Jackson

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