

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Midcontinent)
Independent System Operator)
(MISO))

Order No. 202-26-16

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 1

May Order

Order No. 202-25-3

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

The Midcontinent Independent System Operator (MISO) faces potential tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output. The North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC indicated that “[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output.”¹ In particular, the retirement of thermal generation capacity creates the potential for electricity supply shortfalls. NERC anticipates that the near-term period of highest capacity shortfall for MISO will occur in August.²

Multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), “[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned.”³ Additionally EIA stated, “[t]ypically Michigan’s nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned.”⁴ The state’s Big Rock Point nuclear power plant shut down in 1997 and the Palisades nuclear power plant closed in 2022. While the Palisades nuclear power plant may reopen in 2025, it will not be available during the peak demand period this summer.

The 1,560 MW J.H. Campbell coal-fired power plant in West Olive, MI, is scheduled to cease operations on May 31, 2025. Its retirement would further decrease available dispatchable generation within MISO’s service territory, removing additional such generation along with the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. In 2021, Consumers announced that it planned to “speed closure” of Campbell in 2025, several years before the end of its scheduled design life.⁵ Although MISO and Consumers have

¹ 2025 summer reliability assessment. (May 14, 2025).

https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf

² *Id.*

³ U.S. Energy Information Administration, Michigan State Energy Profile, Oct. 17, 2024, *available at*: <https://www.eia.gov/state/print.php?sid=mi>.

⁴ *Id.*

⁵ <https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation>

incorporated the planned retirement into their supply forecasts and acquired a 1,200 MW natural gas power plant in Covert, MI, the NERC Assessment still anticipates “elevated risk of operating reserve shortfalls.”

MISO’s Planning Resource Auction Results for Planning Year 2025-26, released in April 2025, note that for the northern and central zones, which includes Michigan, “new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources.” While the results “demonstrated sufficient capacity,” the summer months reflected the “highest risk and a tighter supply-demand balance” and the results “reinforce the need to increase capacity.”⁶

ORDER

Given the determination that an emergency exists as discussed above, the responsibility of MISO to ensure reliability of its system, and the ability of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on the insufficiency of dispatchable capacity and anticipated demand during the summer months, and the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety.

This Order is limited in duration to align with the emergency circumstances. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the “hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable,” be consistent with any applicable environmental law and minimize any adverse environmental impacts.

Based on my determination of an emergency set forth above, I hereby order:

- A. From the time this Order is issued on May 23, 2025, MISO and Consumers Energy shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Following conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

⁶ <https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250428694160.pdf>

- B. To minimize adverse environmental impacts, this Order limits operation of dispatched units through the expiration of the Order. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.
- C. All operation of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.
- D. By June 15, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability and economic dispatch of the Campbell Plant consistent with the public interest. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.
- E. The extent to which MISO's current Tariff provisions are inapposite to effectuate the dispatch and operation of the units for the reasons specified herein, the relevant governmental authorities are directed to take such action and make accommodations as may be necessary to do so.
- F. Consumers is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate this order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).
- G. This Order shall not preclude the need for the Campbell Plant to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.
- H. This Order shall be effective upon its issuance, and shall expire at 00:00 EDT on August 21, 2025, with the exception of the reporting requirements in paragraph D and applicable compliance obligations in paragraph E.
- I. Issued in Washington, D.C. at 3:15:pm Eastern Daylight Time on this 23rd day of May 2025.



Chris Wright
Secretary of Energy

cc: **FERC Commissioners**

Chairman Mark Christie
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang

Michigan Public Service Commissioners

Chairman Dan Cripps
Commissioner Katherine Peretick
Commissioner Alessandra Carreon

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Exhibit 2

Grid Strategies June Report



A Review of DOE’s 202(c) Order for the Campbell Coal Plant

Michael Goggin

June 18, 2025

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I. Executive Summary

On May 23, 2025, the U.S. Department of Energy (“DOE”) issued an order under Section 202(c) of the Federal Power Act directing the Midcontinent Independent System Operator (“MISO”) and utility Consumers Energy to take “all measures necessary” to ensure the continued availability of the J.H. Campbell coal power plant in Michigan for three months, past its scheduled retirement date on May 31, 2025.¹ The DOE order claims there is an emergency due to insufficient “dispatchable capacity” in MISO. The order does not define dispatchable capacity and does not clearly indicate the basis on which the Energy Secretary believes there is a shortfall of dispatchable resources. In my experience, “dispatchable” generally refers to generating resources that can change their level of output on command, and a stated lack of “capacity” is a claim that there will be insufficient electricity supply during periods of peak demand, a need often referred to as “resource adequacy.”

This report is organized into four sections. First, it provides brief background on the methods grid planners use to ensure electricity supply is adequate to meet demand. Next, it reviews how utilities, state regulators, regional grid operators, and reliability regulators use planning, regulatory, and market mechanisms to ensure electricity generating supply is adequate to meet demand. Third, it reviews the determinations Consumers Energy, Michigan, and MISO have already made that the Campbell plant is not necessary for meeting anticipated electricity demand this summer, in large part because MISO has a summer capacity surplus of more than 2,600 MW. That section also documents why the North American Electric Reliability Corporation (“NERC”) Summer Reliability Assessment that DOE cites to justify its order does not indicate that an emergency exists in the MISO region. Finally, the report explains why the aging Campbell plant is a poor choice for meeting electricity demand this summer, as evidenced by its low availability rates during recent summer peak demand periods.

II. Background on Resource Adequacy Methods

At the outset, it is helpful to explain some relevant terms. “Resource adequacy” generally means having enough supply during periods of peak net system need from generators and from other resources like demand response (programs by which electricity users are compensated for reducing consumption) and energy storage.

There is no one correct amount of resource adequacy: what level is appropriate depends in part on what system planners, regulators, industry, utilities, customers, government, and other stakeholders want to pay for. This question is one of risk versus reward. More resources can always be added to achieve more resource adequacy, but there are diminishing returns if more is invested. As a result, the usual benchmark for acceptable risk of such events occurring is one day of lost load in ten years. In other words, system planners typically seek to have a set of

¹ U.S. DOE, *Order No. 202-25-3*, (May 23, 2025) available at https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf

resources such that the system can expect to experience no more than one day containing an outage in ten years. Utilities, state regulators, and regional grid operators have coalesced around this benchmark, and have generally concluded that it appropriately balances the cost of building and maintaining generating capacity versus the cost of potential generation shortfalls. Many state regulators use the one day in ten years criterion to ensure profit-maximizing utilities do not burden ratepayers with the cost of excessive generating capacity. This is largely due to the diminishing marginal returns from a higher planning reserve margin,² which is the amount of extra generating capacity that exists in a system above peak load projections, expressed as a percentage of peak load.

To calculate the target reserve margin that achieves a specific risk threshold, planners use sophisticated statistical analyses to simulate electricity demand and supply availability scenarios based on decades of historical weather patterns. The reserve margin thus accounts for interannual variability in peak electricity demand due to extreme weather events and other factors. Planners also use these sophisticated methods to determine the expected contribution of each resource towards meeting peak needs, often called a resource’s “capacity value” or “accredited capacity.” These methods account for how weather patterns affect the timing of wind and solar output, and how unplanned outages and other factors can cause any resource to have reduced availability during periods of need.³ Thus, planners account for all of these risks in setting the target reserve margin.

II. Existing State and Regional Measures Already Ensure Reliability and Resource Adequacy.

The regulation and oversight of power grid reliability and resource adequacy have become far more sophisticated and robust since Section 202(c) of the FPA was enacted in 1935. For most of the past century, states and the electric utilities they regulate have had front-line responsibility for ensuring that adequate resources are available to serve the electric power needs of customers in their jurisdictions. In recent decades, two key developments have layered regional and national assurance mechanisms onto the existing state resource adequacy regulations.

First, the Federal Energy Regulatory Commission (“FERC”) approved the formation of Regional Transmission Organizations (“RTOs”) and Independent System Operators (“ISOs”),

² For example, see K. Carden and A. Dombrowsky, *Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region for 2024 (Final)*, (January 2021) available at [https://www.ercot.com/files/docs/2021/01/15/2020 ERCOT Reserve Margin Study Report FINAL 1-15-2021.pdf](https://www.ercot.com/files/docs/2021/01/15/2020%20ERCOT%20Reserve%20Margin%20Study%20Report%20FINAL%201-15-2021.pdf), at 34-40; and PJM, *2023 PJM Reserve Requirement Study*, (October 2023) available at <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2023/20231115/20231115-consent-agenda-b---2-2023-pjm-reserve-requirement-study-report-final.ashx>, at 27.

³ MISO, *Planning Year 2025-2026 Loss of Load Expectation Study Report*, available at <https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401>, at 20-23.

such as MISO. The RTOs and ISOs operate the bulk power transmission system within their service areas – which in several cases (including MISO) cover multiple states – and manage wholesale electricity markets that help ensure resource adequacy.

Second, Congress enacted Section 215 of the FPA in 2005, creating a new reliability regulatory regime overseen by FERC. Pursuant to Section 215, FERC designated NERC as the national Electric Reliability Organization, with responsibility for setting and enforcing national reliability standards, subject to FERC approval. NERC also designates “Regional Entities” that help implement the national standards in their regions and develop region-specific standards, subject to FERC and NERC approval. ReliabilityFirst Corporation (“RFC”) is the Regional Entity for Michigan and most of eastern MISO. Together, state utility regulators, ISOs and RTOs, NERC and its subsidiary regional reliability organizations, and FERC share responsibility for assuring the electric grid operates reliably.

A. States and Utilities

The states are responsible for ensuring that the utilities they regulate have adequate resources to meet demand for electric power. In most states, including Michigan, utility regulators have processes through which they evaluate utilities’ plans to add new generators, retire old generators, and undertake a host of other activities, with the goal being to identify a prudent resource plan that minimizes costs and risks for ratepayers. I have participated in many of these “integrated resource plan” or “IRP” proceedings, which are detailed, fact-intensive processes in which the regulator and other stakeholders closely review a utility’s proposed assumptions and methods. A primary focus of IRP proceedings is ensuring resource adequacy. State regulators have strong incentives to ensure resource adequacy, as a generation shortfall in a state can result in localized blackouts or increased costs for ratepayers.

B. MISO

MISO plays two important roles in ensuring resource adequacy. First, as discussed further below, MISO is a designated Planning Coordinator responsible for implementing the resource adequacy planning standard adopted by RFC. Pursuant to that standard, MISO performs and documents an annual resource adequacy analysis, which is based on the “one day in ten years” loss of load standard. MISO uses that analysis to determine a planning reserve margin for the region, for each season of the upcoming year. MISO then applies that margin to each zone’s load projections to determine the planning reserve margin requirement for each zone and season.

Second, MISO runs a residual capacity market that allows utilities and generators to buy and sell capacity to meet each of their four seasonal planning reserve margin requirements. MISO and other grid operators also use energy markets and other tools to ensure that electricity supply meets demand at all times. Each of these markets is discussed in more detail below.

1. *Capacity Market*

First, MISO sets the planning reserve margin that it determines is required to meet the “one day in ten years” benchmark, and determines resources’ capacity accreditation, as discussed above. MISO then applies the planning reserve margin to each zone of MISO. As part of this, MISO uses power flow models to assess how transmission constraints affect the need for generation in each zone in the MISO region.⁴ This ensures that there are sufficient resources to meet demand in each zone, after accounting for the transmission capacity available to import power from other zones.

Based on these inputs and zonal requirements, MISO then conducts an annual capacity market auction, and this price signal provides an additional mechanism to incentivize the development and construction of new generation to help meet future resource adequacy needs. The core elements of MISO’s capacity market processes have been approved by FERC under its authority to ensure that rates are just, reasonable, and not unduly discriminatory under Section 205 of the Federal Power Act.⁵

If a utility falls short of its resource adequacy obligation to meet its needs plus MISO’s reserve margin, it must make up for that shortfall through purchases in the capacity market. If supply is short or import purchases begin to approach the import limit MISO has calculated for a given zone, the price of capacity in that zone will increase. State regulators are cognizant of that risk, and thus have a strong incentive to ensure their utilities have adequate supplies in advance.

2. *Real-Time and Near-Term Operations*

Each day MISO runs a day-ahead energy market in which generators offer to produce electricity each hour of the next day at a certain price. MISO then compares this supply curve of offers to its demand forecast for the next day, and then “commits” the generators that can meet this demand forecast at lowest cost subject to reliability and transmission constraints. Generators that are committed but were offline start and take other steps required to be online by the next day. The vast majority of electricity is procured in the day-ahead market, but MISO also runs a real-time energy market to fine-tune deviations in supply and demand that occur after the day-ahead market has concluded. The energy markets play an important role in ensuring supply is adequate to meet demand by sending a powerful price signal for generators to maximize their output and for utilities to import power from neighboring regions during periods of need.

MISO also operates “ancillary services” markets, which procure other services like operating reserves from flexible resources that help balance fast variability in supply and demand. Prices in these markets are typically very low as MISO has a large supply of flexible

⁴ *Id.* at 36-55.

⁵ FERC Docket Nos. 11-4081; EL15-70 *et al.*; ER22-495; ER23-2977; ER24-1638.

resources,⁶ and that supply is increasing as batteries and other flexible resources replace inflexible coal and nuclear generators.

As a result, there is no indication of a need for “dispatchable” resources, as claimed by DOE’s Order, to provide additional flexibility in MISO. If a need for more flexibility arose at any point in time, prices for ancillary services would simply increase, spurring flexible generators that were offline to start up and provide flexibility until the need has passed. Regardless, coal plants like Campbell are not very dispatchable compared to other generating resources, with long startup times, slow output ramp rates, and high minimum output levels. This can also reduce their capacity contribution to meeting peak demand needs, particularly those that arise on short notice.

If MISO encounters a risk of a generation shortage in real-time operations, it has numerous additional tools that it can deploy in a stepwise fashion to help ensure supply is adequate to meet demand.⁷ The impact of many of these steps is not fully accounted for in MISO’s loss of load analysis, making that planning conservative.

Days in advance of expected extreme heat, cold, or other severe weather, MISO can issue an alert or declare Conservative System Operations, directing transmission and generating resources on planned outages to return to service and make other preparations.⁸ NERC notes this step helped ensure resource adequacy in MISO last summer.⁹ As noted below, NERC’s “elevated risk” designation for MISO is based on the assumption that many generators are on outage, so by taking steps to reduce generator outages MISO can reduce that risk.

Next, MISO can progress to issuing a capacity warning, which activates numerous additional steps to increase supply, including activating emergency pricing, and curtailing non-firm exports.¹⁰ If the event then progresses to step 1a, MISO activates demand response resources, which are customers that are compensated for reducing their demand during periods of need. If an event progresses to step 1b, generating units are directed to operate at their

⁶ Potomac Economics, 2023 State of the Market Report for the MISO Electricity Markets, (June 2024) available at https://www.potomaceconomics.com/wp-content/uploads/2024/06/2023-MISO-SOM_Report_Body-Final.pdf, at 8-9.

⁷ MISO, *MISO Market Capacity Emergency*, available at <https://cdn.misoenergy.org/SO-P-EOP-11-002%20Rev%2021%20MISO%20Market%20Capacity%20Emergency683501.pdf>, at 37-39.

⁸ MISO, *Conservative System Operations*, available at <https://cdn.misoenergy.org/SO-P-NOP-00-449%20Rev%2010%20Conservative%20System%20Operations688847.pdf>

⁹ NERC, *2025 Summer Reliability Assessment*, (May 2025) available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf, at 51, referring to summer 2024: “MISO experienced peak electricity demand during late August. Demand was between the normal and 90/10 summer peak forecast levels. Wind and solar resource output at the time of peak demand were near expectations for summer on-peak contributions. Forced outages of thermal units, however, were lower than expected. On the day prior to MISO’s peak demand, operators issued advisories to maximize generation. Similar advisories were issued earlier in the summer, coinciding with above-normal temperatures and periods of high generator forced outages.”

¹⁰ MISO, *MISO Market Capacity Emergency*, available at <https://cdn.misoenergy.org/SO-P-EOP-11-002%20Rev%2021%20MISO%20Market%20Capacity%20Emergency683501.pdf>, at 10-12.

emergency maximum limits. If the event escalates further, MISO can then progress through additional steps including activating additional tiers of demand response resources, issuing public conservation requests, procuring emergency energy, and directing resources with environmental de-rates to request waivers, all before load is shed.¹¹

C. NERC

Pursuant to Section 215 of the Federal Power Act, FERC certified NERC as the Electric Reliability Organization responsible for developing mandatory reliability standards, subject to FERC's review and approval. NERC also annually assesses seasonal and long-term reliability of the bulk power system and monitors system performance.

1. *Mandatory Reliability Standards*

NERC Regional Entity RFC has imposed a mandatory standard for Planning Resource Adequacy Analysis, Assessment, and Documentation for the region that includes Michigan. As the Planning Coordinator for Michigan, MISO is required to annually calculate the planning reserve margin required to meet the one day in ten years benchmark.¹² The standard also requires certain methods for the load forecast and the capacity accreditation for resources and imports.

Like other NERC and Regional Entity standards, this requirement is enforceable with fines of up to \$1 million per day per violation. This further ensures MISO conducts robust and standardized resource adequacy planning, and each year MISO extensively documents that its planning methods fully meet this standard.¹³

2. *Reliability Assessments*

NERC also conducts periodic assessments of reliability in the country, including a summer, winter, and long-term reliability assessment every year. In the seasonal assessments, NERC groups regions into three categories for risk of resource adequacy shortfalls, as shown in the NERC figure below.¹⁴ MISO's categorization as "elevated" risk in this year's NERC Summer Reliability Assessment is the middle of three risk categories, below "high" and above

¹¹ *Id.* at 38-39.

¹² NERC, *Standard BAL-502-RFC-02*, available at <https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-502-RFC-02.pdf>

¹³ See, e.g., MISO, *Planning Year 2025-2026 Loss of Load Expectation Study Report*, available at <https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401>, at 56-60.

¹⁴ NERC, *2025 Summer Reliability Assessment*, (May 2025) available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf, at 10.

“normal.” In its 2023¹⁵ and 2024¹⁶ Summer Reliability Assessments, NERC respectively identified 8 and 5 out of 13 U.S. regions as having elevated risk. Despite half of U.S. regions being designated as having elevated risk, there were no resource adequacy shortfalls in either summer.

Table 1: Seasonal Risk Assessment Summary	
Category	Criteria ¹
High Potential for insufficient operating reserves in normal peak conditions	- Planning Reserve Margins do not meet Reference Margin Levels; or - Probabilistic indices exceed benchmarks (e.g., LOLH of 2.4 hours over the season); or - Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under normal peak-day demand and outage scenarios²
Elevated Potential for insufficient operating reserves in above-normal conditions	- Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours over the season); or - Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under extreme peak-day demand with normal resource scenarios (i.e., typical or expected outage and derate scenarios for conditions);² or - Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under normal peak-day demand with reduced resources (i.e., extreme outage and derate scenarios)³
Normal Sufficient operating reserves expected	- Probabilistic indices are negligible - Analysis of the risk hour(s) indicates resources will be sufficient to meet operating reserves under normal and extreme peak-day demand and outage scenarios⁴
Table Notes: ¹The table provides general criteria. Other factors may influence a higher or lower risk assessment. ²Normal resource scenarios include planned and typical forced outages as well as outages and derates that are closely correlated to the extreme peak demand. ³Reduced resource scenarios include planned and typical forced outages and low-likelihood resource scenarios, such as extreme low-wind scenarios, low-hydro scenarios during drought years, or high thermal outages when such a scenario is warranted. ⁴Even in normal risk assessment areas, extreme demand and extreme outage scenarios that are not closely linked may indicate risk of operating reserve shortfall.	

Figure 1: NERC table showing categories used for regions’ seasonal risk

III. There Is No Evidence Consumers Energy, Michigan, or MISO Has a Resource Adequacy Emergency this Summer.

Michigan utility regulators and Consumers Energy have determined that Campbell was not needed to meet resource adequacy needs, a conclusion confirmed by MISO’s resource adequacy analysis and capacity market results showing a capacity surplus for this summer. Moreover, NERC’s Summer Reliability Assessment does not indicate MISO has a supply emergency.

¹⁵ NERC, 2023 Summer Reliability Assessment, (May 2023) available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2023.pdf, at 6.

¹⁶ NERC, 2024 Summer Reliability Assessment, (May 2024) available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf, at 6.

A. Michigan

Consumers Energy completed comprehensive reliability and economic modeling in its 2021 IRP, overseen by the Michigan Public Service Commission with robust engagement from stakeholders. As explained above, a cornerstone of this and all IRPs is ensuring resource adequacy needs are met. The utility,¹⁷ the Commission,¹⁸ and other stakeholders concluded that it was more economic and reliable to replace Campbell with a variety of other resources, including by (1) acquiring the nearby 1,200 MW gas-fired Covert Generating Station, which Consumers Energy subsequently purchased in May 2023, and (2) adding nearly 1,600 MW of demand response and energy efficiency by 2025.¹⁹

Michigan utilities are also bound by the state's Public Act 341 of 2016, which requires them to demonstrate to the Michigan Public Service Commission that they have sufficient generating capacity to meet their capacity obligations. The Commission can impose a state reliability mechanism capacity charge on utilities that fail to meet that requirement. In June 2022, the Commission approved Consumers Energy's demonstration for the 2025/2026 planning year,²⁰ and more recently Consumers successfully made this demonstration for the 2027/2028 planning year²¹ and filed its demonstration for 2028/2029.²²

Confirming that state and regional officials stand by their determination that the Campbell plant is not needed, the Chair of the Michigan Public Service Commission recently indicated that MISO, Michigan, and Consumers Energy did not ask to keep the Campbell plant online.²³

¹⁷ CMS Energy, *Integrated Resource Plan*, (June 2021) available at https://s26.q4cdn.com/888045447/files/doc_presentations/2021/06/2021-Integrated-Resource-Plan.pdf

¹⁸ Michigan Public Service Commission, *Exhibit A: Settlement Agreement*, <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000003KjSDAA0> (beginning at page 98 in the pdf)

¹⁹ *Id.* at 4 (101 in the pdf).

²⁰ See the discussion of Case No. U-21099 at Michigan Public Service Commission, *MPSC approves Consumers Energy integrated resource plan settlement agreement, takes additional steps to boost electric capacity*, (June 2022) available at

<https://www.michigan.gov/mpsc/commission/news-releases/2022/06/23/mpsc-approves-consumers-irp-takes-steps-improve-capacity>

²¹ Michigan Public Service Commission, *Order*, Case Nos. U-21393 and U-21775, (August 2024) available at <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs000005gPyUAAU>

²² Consumers Energy, *Redacted Version of Consumers Energy Company's Capacity Demonstration for Planning Year 2028/2029*, (February 2025) available at <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000bz8crAAA>

²³ C. Brown and H. Stevens, *Coal and Gas Plants Were Closing. Then Trump Ordered Them to Keep Running*, (June 2025) available at <https://www.nytimes.com/2025/06/06/climate/trump-coal-gas-plants-energy-emergency.html>

B. MISO

Based on the loss of load analysis discussed above, MISO has concluded that it has “surplus capacity” for this summer, without Campbell.²⁴ The 2025/26 capacity auction yielded summer capacity supplies 2,623 MW or 2.2 percentage points above the summer reserve margin target of 7.9%, which was calibrated to meet the one day in ten years loss of load benchmark.²⁵ In other words, MISO would still meet this stringent reliability benchmark this summer even if an additional 2,623 MW of additional capacity unexpectedly were unavailable, and retaining Campbell would only increase MISO’s already-generous capacity surplus for this summer beyond 4 GW. As noted above, capacity supply above the reserve margin target provides diminishing marginal returns.

The zonal results from MISO’s 2025/26 capacity auction also confirm there is no resource adequacy shortfall this summer in Zone 7, which is the MISO footprint in Michigan’s Lower Peninsula. Zone 7 has 1.2 GW of supplies above the summer Local Clearing Requirement, which is the amount of capacity that MISO has concluded must come from within Zone 7 after accounting for transmission constraints.²⁶

C. NERC’s Summer Reliability Assessment Does Not Indicate a Supply Emergency.

The NERC Summer Reliability Assessment that DOE cites in an attempt to justify the Campbell 202(c) order is based on information reported by MISO and other regional grid operators. Thus, the NERC assessment does not contradict MISO’s conclusion that it has a capacity surplus above what it needs to meet its reliability target. In fact, NERC notes that for MISO, “Expectations for load loss and unserved energy are less than these amounts because MISO’s resources are above the Reference Margin Level,” which is MISO’s reserve margin target calibrated to achieve a loss of load risk of one day in 10 years.²⁷

NERC including MISO in the “elevated” summer risk category does not indicate a supply emergency. This year’s Summer Reliability Assessment identifies four U.S. regions as having elevated risk, plus one region each in Canada and Mexico. As noted above, across the 2023 and 2024 Summer Reliability Assessments NERC identified half of U.S. regions as having elevated risk, yet there were no resource adequacy shortfalls in either summer.

This year’s Summer Reliability Assessment finds that MISO has a 24.7% reserve margin, which NERC calculates corresponds to a 9.3% reserve margin with typical generator outage

²⁴ MISO, *Planning Resource Auction Results for Planning Year 2025-26 (Corrections, reposted 05/29/25)*, available at https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf at 4.

²⁵ *Id.* at 3, 4, 37.

²⁶ *Id.* at 18.

²⁷ NERC, *2025 Summer Reliability Assessment*, (May 2025) available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf, at 12.

rates. NERC’s finding of elevated risk only indicates a “Potential for insufficient operating reserves in above-normal conditions.”²⁸ NERC finds that MISO would only see a generation shortfall with a perfect storm of 90th percentile demand (*i.e.*, demand is higher than expected in 9 out of 10 years) at the same time that MISO sees its highest historical rate for generator outages and derates due to “extreme conditions,” and even in that worst case scenario it would only have a 1.9% shortfall.²⁹ By way of comparison, NERC’s 2023 and 2024 Summer Reliability Assessments projected MISO would have a 6.9% and 6.3% shortfall under that worst case scenario, respectively, yet NERC still did not designate the risk as “high,” and MISO ultimately had more than adequate supplies in both summers.

As explained above, MISO and utility reserve margins are already designed to accommodate wide interannual variability in electricity demand and generator outages, and MISO has calibrated its summer reserve margin to the stringent requirement that it only experience one day of shortfall in 10 years. Moreover, NERC notes that Michigan and the rest of MISO have the lowest risk of any region for seeing above average temperatures this summer.³⁰

D. The NERC and MISO resource adequacy studies are likely conservative.

NERC’s Summer Reliability Assessment and MISO’s loss of load analysis both use conservative assumptions for the availability of imports and renewable output in MISO.

NERC’s analysis does not fully account for MISO’s ability to import power during periods of need, even though MISO successfully tapped into the supply and demand diversity provided by its neighbors to import more than 13 GW during Winter Storm Uri³¹ and 4.5 GW during Winter Storm Elliott.³² Other studies have documented significant diversity between MISO and its neighbors in the timing of peak demand, lulls in renewable output, and correlated thermal generator outage and derate events, including summer heat waves.³³ These geographic diversity benefits are due to inherent climate and weather diversity, and the fact that extreme heat and cold events are only at their most severe in small geographic areas that move over the course of an event.

²⁸ *Id.* at 6.

²⁹ *Id.* at 10, 16.

³⁰ *Id.* at 9.

³¹ M. Goggin, *Transmission Makes the Power System Resilient to Extreme Weather*, (July 2021) available at <https://gridstrategiesllc.com/wp-content/uploads/2024/05/transmission-makes-the-power-system-resilient-to-extreme-weather.pdf>, at 7.

³² M. Goggin and Z. Zimmerman, *The Value of Transmission During Winter Storm Elliott*, (February 2023) available at <https://acore.org/wp-content/uploads/2023/02/The-Value-of-Transmission-During-Winter-Storm-Elliott-ACORE.pdf>

³³ A. Brooks, A. Silverstein, and R. Gramlich, *Resource Adequacy Value of Interregional Transmission*, (June 2025) available at https://gridstrategiesllc.com/wp-content/uploads/GridStrategies_RAValueInterregionalTx_250601.pdf; M. Goggin, Z. Zimmerman, and A. Sherman, *Quantifying a Minimum Interregional Transfer Capability Requirement*, (May 2023) available at https://gridstrategiesllc.com/wp-content/uploads/2023/05/GS_Interregional-Transfer-Requirement-Analysis-final54.pdf

DOE’s National Transmission Planning Study documented the geographic diversity phenomenon with a compelling set of maps.³⁴ Those maps show that during the event when MISO saw the highest demand in the period 2007-2013, the Southwest Power Pool and the Southeast had significantly lower demand. Similar maps in the study show significant diversity in when MISO and its neighbors experience lulls in wind or solar output.³⁵

NERC has previously noted that “MISO benefits from significant transfer capacity with neighboring assessment areas...”³⁶ Data in NERC’s 2025 Summer Reliability Assessment documents that these neighboring grid operators have large reserve margin surpluses this summer, which further increases the availability of imports from those regions. NERC projects the summer reserve margin surplus under typical generator outage rates for the Southwest Power Pool at 18.2%, Ontario at 23.4%, PJM at 15.0%, the SERC Central region at 12.7%, and Manitoba at 11.2%.³⁷ As a result, at least some of those regions are highly likely to have surplus generating resources if MISO experiences periods of high demand or low supply this summer.

When calculating the reserve margin needed to meet the 1 day in 10 year target, MISO’s loss of load study also makes conservative assumptions for the availability of imports from other regions. While MISO conducts robust statistical modeling of historical import availability, this analysis is conservative because hours in which MISO was exporting or minimally importing due to a lack of need are included in the dataset, even though MISO likely could have imported or at least reduced exports in those hours if needed.³⁸

If there were a true resource adequacy emergency in MISO, a potential solution would be to issue a Section 202(c) order to facilitate interchange with neighboring grid operators. As the MISO independent market monitor³⁹ and others⁴⁰ have documented, inefficient pricing of market transactions along MISO’s seams with neighboring grid operators can interfere with the efficient flow of power during shortage events. DOE could work with MISO and other stakeholders to improve the efficient flow of power across MISO’s seams, improving the availability of imports during periods of peak need.

³⁴ DOE, *National Transmission Planning Study: Chapter 2*, (October 2024) available at <https://www.energy.gov/sites/default/files/2024-10/NationalTransmissionPlanningStudy-Chapter2.pdf>, at 53.

³⁵ *Id.* at 51 and 52.

³⁶ NERC, *2024 Long Term Reliability Assessment*, (December 2024) available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf, at 44.

³⁷ NERC, *2025 Summer Reliability Assessment*, (May 2025) available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf, at 10.

³⁸ MISO, *Planning Year 2025-2026 Loss of Load Expectation Study Report*, available at <https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401>, at 33.

³⁹ Potomac Economics, *2023 State of the Market Report*, (June 2024) available at <https://cdn.misoenergy.org/2023%20State%20of%20the%20Market%20Report636641.pdf>, at xiv-xv.

⁴⁰ J. Pfeifferberger and N. Bay, *Intertie Optimization: Efficient Use of Interregional Transmission (Update)*, (April 2024) available at <https://www.brattle.com/wp-content/uploads/2024/04/Intertie-Optimization-Efficient-Use-of-Interregional-Transmission-Update.pdf>

If DOE's claim of resource adequacy risk in MISO were true, facilitating interchange with neighboring grid operators would be more appropriately tailored to address the risk. This is because loss of load probability is concentrated into a narrow slice of hours on a small number of days when high demand coincides with low supply. Increased interchange can occur during just those hours, tapping into diversity in the timing of peak need between MISO and its neighbors. In contrast, retaining the Campbell coal plant for the entire summer is not well-tailored for meeting DOE's claimed emergency.⁴¹

MISO and NERC also appear not to have accounted for the fact that low wind speed events are negatively correlated with low solar output events. For example, wind speeds tend to be low during high pressure heat dome events, which tend to cause high solar output because there are fewer clouds during such events. Conversely, stormy conditions that result in reduced solar output due to clouds tend to be correlated with high wind output. As NERC notes, MISO has over 31 GW of wind and 18 GW of solar, so one resource can make up for shortfalls of the other.⁴² As noted above, there is also significant diversity in when MISO and its neighboring regions experience lulls in renewable output. MISO meteorologists have also "projected normal to above-normal wind generation" for this summer.⁴³

IV. Consumers Energy May Need to Buy Coal to Comply with DOE's Order.

The DOE data shown below indicate that coal supplies at the plant appear to have been drawn down in advance of its anticipated retirement, with enough coal remaining onsite as of the end of March 2025 to operate the plant for only about two to three weeks.⁴⁴ The DOE data indicate the plant is supplied via rail deliveries from a coal mine in Wyoming.⁴⁵

⁴¹ As DOE's Campbell order notes, "FPA section 202(c) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts." U.S. DOE, *Order No. 202-25-3*, (May 23, 2025) https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf, at 2.

⁴² NERC, *2025 Summer Reliability Assessment*, (May 2025) available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf, at 16.

⁴³ MISO, *2025 Summer Readiness Workshop*, (May 2025) available at <https://cdn.misoenergy.org/20250508%20Summer%20Readiness%20Workshop%20Items%2002-04%20Presentation695282.pdf>, at 17.

⁴⁴ DOE Energy Information Administration, *EIA-923 March 2025*, (May 2025) available at <https://www.eia.gov/electricity/data/eia923/>, with monthly stocks calculated by taking coal stock data as of December 2023 and then subtracting monthly consumption and adding monthly deliveries.

⁴⁵ *Id.*

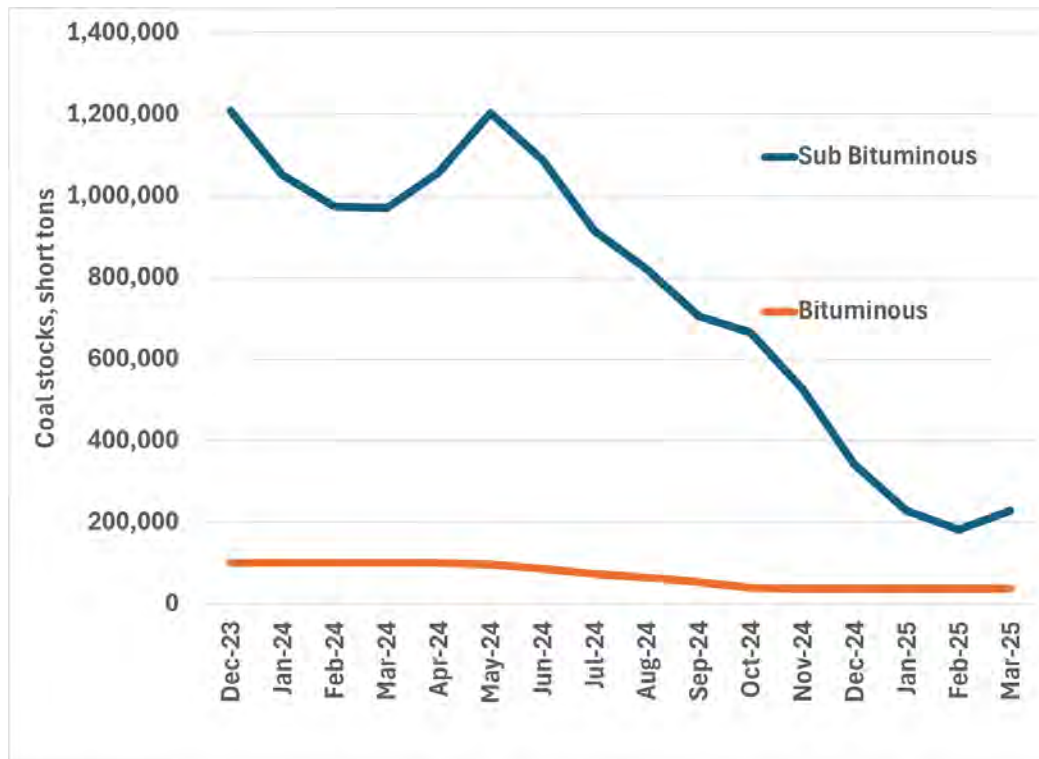


Figure 2: Coal supplies at Campbell, per DOE data

V. Qualifications of Michael Goggin

Michael Goggin has worked on electricity market and reliability issues for over 20 years. At Grid Strategies he serves as an expert on those topics for a range of clients including state utility regulators, grid operators, and non-profit organizations. He has testified as an expert in dozens of proceedings before state utility commissions in Arizona, Colorado, Georgia, Iowa, Illinois, Indiana, Wisconsin, Louisiana, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, South Carolina, Virginia, Washington, and Wisconsin, as well as before FERC.

For the preceding ten years Michael worked at the American Wind Energy Association (now known as the American Clean Power Association), where he provided technical analysis regarding renewable energy, transmission, and wholesale electricity markets, including directing the organization's research and analysis team from 2014-2018. Prior to the American Wind Energy Association, he worked at a firm serving as a consultant to DOE, and at two environmental groups.

In the course of that work, Michael has co-authored more than one hundred filings to FERC; served as a technical reviewer for over a dozen national laboratory reports, academic articles, and renewable integration studies; published academic articles and conference presentations on renewable integration, transmission, and policy; and been elected to the Standards, Operating, and Planning Committees of NERC. He graduated with honors from Harvard University. His recent publications are available at <https://gridstrategiesllc.com/reports/>.

VI. Sources

The principal documents I relied on in preparing this report include the materials listed below and in footnotes. To the extent feasible, relevant documents are included in the Appendix of the Request for Rehearing.

-MISO, *Planning Year 2025-2026 Loss of Load Expectation Study Report*, available at <https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401>

-MISO, *Planning Resource Auction Results for Planning Year 2025-26 (Corrections, reposted 05/29/25)*, available at https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf

-MISO, *MISO Market Capacity Emergency*, available at <https://cdn.misoenergy.org/SO-P-EOP-11-002%20Rev%2021%20MISO%20Market%20Capacity%20Emergency683501.pdf>

-U.S. EPA, *Continuous Emission Monitoring Systems: Custom Data Download*, available at <https://campd.epa.gov/data/custom-data-download>

-NERC, *Standard BAL-502-RFC-02*, available at <https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-502-RFC-02.pdf>

-NERC, *2025 Summer Reliability Assessment*, (May 2025) available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf

-Michigan Public Service Commission, *Exhibit A: Settlement Agreement*, <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000003KjSDAA0> (beginning at page 98 in the pdf)

DOE Energy Information Administration, *EIA-923 March 2025*, (May 2025) available at <https://www.eia.gov/electricity/data/eia923/>



Michael Goggin
Vice President
Grid Strategies, LLC

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Midcontinent)
Independent System Operator)
(MISO))

Order No. 202-26-16

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 3

Powers June Decl.

DECLARATION OF BILL POWERS, P.E.

I, Bill Powers, P.E., declare as follows:

1. I am the principal of Powers Engineering, an engineering firm that consults on issues related to the operation of, and control of pollution from, power plants, including coal-fired power plants. My office is located in San Diego, California. My professional and educational experience is summarized in the curriculum vitae attached to this declaration (Attachment A).

2. I received a Bachelor of Science degree from Duke University in Mechanical Engineering and a Master of Public Health degree in Environmental Sciences from the University of North Carolina. I am a registered engineer in the state of California.

3. I have been an independent engineering consultant with a focus on power systems since 1994. In prior employment, I received “Engineer of the Year” awards from ENSR Consulting and Engineering in 1991 (before ENSR merged with AECOM) and from the Naval Energy and Environmental Support Activity (“NEESA”) office within the U.S. Navy in 1986 (before NEESA was subsumed by the Naval Facilities Engineering Service Center). I also received a “Productivity Award of Excellence” from the U.S. Department of Defense in 1985. I worked extensively on Navy and Marine Corps shore installation of coal-fired power plants in the 1980s as a Navy civilian engineer.

4. I have over 40 years of experience in the fields of power plant operations and environmental engineering. My technical specialties include, among others: combustion equipment permitting, testing, and monitoring; air emission control assessments; air pollution control equipment retrofit design/performance; and power plant cooling system conversion.

5. I have served as an engineering expert for a wide array of clients, including private companies, non-profits, and government entities, including the cities of Carlsbad, California and Houston and Dallas, Texas. In this role, I have provided expert testimony, conducted feasibility studies, and consulted on power plant engineering issues in a number of states, including Arkansas, California, Connecticut, Florida, Georgia, Kentucky, Maryland, Missouri, Nevada, North Carolina, New York, and Tennessee.

6. I have extensive experience with coal-fired power plants. For example, in 2022 I provided expert testimony before the North Carolina Public Utility Commission regarding Duke Energy's proposed plan to maintain coal-fired units in its electric supply portfolio—a proposal that was justified in part on the company's belief that those units were necessary to meet winter peak demand. Throughout my career, I have consulted on the operation of, and control of pollution from, coal-fired power plants. Examples include serving as the lead engineer on a system and performance audit of continuous emissions monitoring systems at a coal-fired power plant in Nevada, and on a project to assess and address the root causes of opacity exceedances at Ameren Missouri's Labadie, Meramec, and Rush Island coal-fired power plants. I have also frequently provided expert testimony on coal-fired power plants. For example, I testified on air pollution controls at a coal-fired power plant in Massachusetts, and on the correlation between a Georgia coal-fired power plant's particulate matter emissions and opacity excursions, among other issues. I also served as a testifying expert on an evaluation of the air emissions limits and control technologies for a proposed coal-fired power plant in Arkansas.

7. I am very familiar with "peaking" units that are intended to ramp up and provide electricity during times of peak demand, such as during hot summer months. For example, in 2001, I prepared all aspects of the air permit applications for five 50 MW simple-cycle gas

turbine installations in response to an emergency request by the California state government for additional peaking power.

8. I am familiar with the U.S. Department of Energy’s (“DOE”) May 23, 2025 order regarding Consumers Energy Company’s (“CECo”) J.H. Campbell coal-fired power plant (Order No. 202-25-3) (“Order”).

9. The J.H. Campbell coal-fired power plant (“Campbell”) consists of three coal-fired generating units. The in-service dates for Units 1, 2, and 3 are 1962, 1967, and 1980 respectively.¹ The nameplate capacity for Unit 1 is 265.2 MW; for Unit 2 is 378.8 MW; and for Unit 3 is 916.8 MW.² Under CECo’s 2021 integrated resource plan (“IRP”), which was approved with modifications by the Michigan Public Service Commission (“Michigan PSC”) in 2022, the Campbell units were scheduled to retire on or before May 31, 2025.

10. I was asked by Earthjustice to develop an opinion on: (A) the extent to which Campbell can operate reliably after May 31, 2025; (B) whether Campbell can operate effectively as a peaking unit; and (C) easily attainable steps DOE can require to ensure Campbell’s operations are consistent with environmental requirements and minimize adverse environmental impacts. A list of materials I reviewed in developing my opinion is attached (Attachment B).

11. While there may be alternatives to Campbell available to DOE to address the circumstances DOE describes in the Order, I do not opine on these alternatives. I also do not opine on the claimed energy emergency described in the Order.

¹ Michigan PSC Case No. U-21585, Direct Testimony of Richard T. Blumenstock on Behalf of CECo, p. 7, Tbl. 1 (May 2024).

² EIA, Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860) (Apr. 2025), <https://www.eia.gov/electricity/data/eia860m/> (showing nameplate capacity).

A. The extent to which Campbell can operate reliably beginning June 1, 2025

12. In my professional opinion, it is unlikely that Campbell can be depended upon to operate reliably in its current state as of June 2025.³ This is especially true if the plant is required to run for extended periods of time; is required to stop and start numerous times; or attempts to start up at an accelerated rate in response to extreme demand conditions.

13. Even before the scheduled retirement date of May 31, 2025, Campbell suffered from poor reliability. Nationally, the average coal unit forced outage rate in 2023 was 12.0 percent.⁴ In contrast, Campbell Units 1-3 had forced outage rates in 2024 of 14.84 percent, 48.07 percent, and 19.25 percent, respectively⁵—well above the average coal unit forced outage rate. The forced outage rates in 2023 were similarly high: Units 1-3 had forced outage rates of 18.66 percent, 57.32 percent, and 22.41 percent, respectively.⁶

14. “Availability” is a measure of the percent of time a unit is not in planned or forced outage and is available to generate electricity. Campbell has lower availability than coal units of comparable size. When CECo compared the availability of the Campbell units in 2019-2023 to similarly sized and fueled generating units, the company found that “[t]he availability of Campbell Units 1, 2, and 3 were all below the five-year comparisons.”⁷

15. The nature of the Unit 1-3 outages in 2023 and 2024 reflects the impact of worn and difficult-to-repair or replace coal unit components on operational reliability. Outages tended to be long and recurrent. Tables 1 and 2 document the longest Unit 1-3 outages by description and duration in 2024 and 2023, respectively. The long outages on Units 1 and 2, and the types of

³ CECo filed testimony regarding Campbell on June 2, 2025, in its most recent rate case before the Michigan PSC.

⁴ NERC, *2024 State of Reliability*, p. 59 (June 2024).

⁵ Michigan PSC Case No. U-21424, Direct Testimony of Nathan J. Hoffman on Behalf of CECo, Ex. A-15 (Mar. 2025).

⁶ Michigan PSC Case No. U-21258, Direct Testimony of Nathan J. Hoffman on Behalf of CECo, Ex. A-14 (Mar. 2024).

⁷ U-21424, Hoffman Direct Testimony, p. 22 & Ex. A-16.

failures, are the predictable result of old equipment, no capital investment, and minimal maintenance.

Table 1. Longest 2024 Outages by Type, Units 1-3 - Description and Duration⁸

Unit	Outage description	Total duration (hours)
1	• degraded governing valve (3 outages)	911
	• worn leaking superheater tube (1 outage)	491
2	• obsolete boiler feedwater pump failure (1 outage)	1,417
	• degraded valve(s) malfunction (3 outages)	1,723
	• worn equipment leaks, various (4 outages)	854
3	• worn/failed turbine turning gear ⁹ (1 outage)	1,104
	• worn tube leak (1 outage)	356

Table 2. Longest 2023 Outages by Type, Units 1-3 - Description and Duration¹⁰

Unit	Outage description	Total duration (hours)
1	• worn leaking valve and superheater tube (2 outages)	661
2	• obsolete boiler feedwater pump failure (4 outages)	3,445
	• worn equipment leaks (3 outages)	571
3	• worn leaking boiler/superheater tubes (3 outages)	1,857
	• worn/vibrating turbine bearings (1 outage)	426

16. In my professional opinion, Campbell will continue to degrade in 2025 due to the continued lack of capital investment and minimal major maintenance spending.

17. CEC Co dramatically reduced capital and major maintenance spending on Units 1-3 following the IRP that established a May 2025 retirement date. CEC Co reduced its capital spending on the units in the 2022-2025 period by approximately 91 percent compared to the amount the company projected to spend in the same period if Units 1-2 operated until 2031 and Unit 3 operated until 2039 (the retirement dates CEC Co originally proposed in its IRP). Likewise, CEC Co reduced its major maintenance spending on the units in the 2022-2025 period by 62-78

⁸ U-21424, Hoffman Direct Testimony, Ex. A-11.

⁹ *Ibid.*, Ex. A-13. The stated scope of the turbine turning gear repair was to “[f]abricate replacement planetary gears and drive shaft to allow for unit operation until the planned retirement in 2025.”

¹⁰ U-21258, Hoffman Direct Testimony, Ex. A-10.

percent (approximately 72% total across all three units). The reductions in capital and major maintenance spending are summarized in Table 3.¹¹

Table 3. Reductions in CECo Capital and Major Maintenance Spending on Campbell Units 1-3, 2022-2025

Capital spending	Pre-IRP projected spend 2022-25 (\$MM)	Post-IRP actual/projected spend 2022-25 (\$MM)	% reduction
Units 1&2	60.6	4.1	93
Unit 3	85.5	8.4	90
Major maintenance spending			
Units 1&2	14.4	5.5	62
Unit 3	23.5	5.1	78

18. Some of the capital and major maintenance projects that CECo cancelled in 2022-2025 were reliability projects, while others were air emission control system projects. Regarding the reliability projects that CECo originally planned to carry out (before deciding to retire Units 1-3 in May 2025), CECo likely believed they were necessary to maintain adequate unit reliability and that failure to carry out the projects could compromise that reliability. But CECo then determined that those projects were unnecessary with the May 2025 retirement. Therefore, it is unlikely that Campbell can reliably dispatch given this deferred capital and major maintenance spending.

19. A detailed listing of the 2022-2025 capital projects that CECo projected carrying out before deciding to retire the units in May 2025 is shown in the left-hand column of Tables 4a (Units 1 and 2) and 4b (Unit 3).¹² As can be seen from the middle column in these tables,¹³ CECo did not carry out most of those projects.

¹¹ Table 3 summarizes the information presented in Tables 4a, 4b, 5a, and 5b, which are based on CECo filings with the Michigan PSC.

¹² Information in the left-hand column is from witness Kapala's testimony in CECo's 2021 IRP case. See Michigan PSC Case No. U-21090, Revised Direct Testimony of Norman J. Kapala, pp. 13-18 (Oct. 2021).

¹³ Information in the middle column is from witness Blumenstock's testimony in CECo's 2023-2025 rate cases. See Ex. A-12 to the Direct Testimony of Richard T. Blumenstock in Michigan PSC Case Nos. U-21389 (May 2023), U-21585 (May 2024), and U-21870 (June 2025).

20. Table 4a compares (i) the capital projects CECo proposed carrying out for Units 1 and 2 before deciding to retire those units in May 2025 with (ii) those projects CECo has actually carried out, or plans to carry out, after making that retirement decision. Capital spending dropped by two-thirds on Units 1 and 2 in 2022, from the proposed \$12.6 million to \$4.1 million. No capital spending occurred in 2023-2024, and no capital spending has yet occurred or is expected to occur in 2025 as of CECo's June 2025 rate case filing. Cancelled capital projects with a direct impact on unit reliability include, among others, partial replacement of the Unit 1 superheat outlet pendant and replacement of the Unit 2 burner assemblies and horizontal reheat system.

Table 4a. Units 1&2 Capital Spend: CECo pre-IRP projection vs. post-IRP actuals/projections

Pre-IRP projection	Post-IRP actuals/projections	Difference
2022 projected spend (in 2021): \$12,556,500 \$7,300,000 at Campbell Unit 1, including: • PJFF Bag Replacement (\$1,578,000) • Superheat Outlet Pendant – partial replacement (\$3,490,000) • Five additional projects totaling \$2,232,000 \$5,256,500 at Campbell Unit 2, including: • Catalyst Management (\$1,120,000) • Replace Burner Assemblies (\$1,350,000) • Six additional projects totaling \$2,786,500	2022 actual expenditure: \$4,067,000 The 2022 actual capital expenditure primarily consisted of two projects, both on Unit 1: air preheater baskets and seals (\$1,819,000), and pulse jet fabric filter bags (\$1,040,000).	\$8,489,500
2023 projected spend (in 2021): \$16,686,700 \$7,214,680 at Campbell Unit 1, including: • PJFF Filter Bag Replacement (\$1,514,100) • Replace Air Preheater Baskets and Seals (\$1,113,400) • Distributed Control System and Simulator Upgrade (\$1,500,000) • Ashpit Rebuild (\$1,000,000) • Twelve additional projects totaling \$2,087,180 \$9,472,020 at Campbell Unit 2, including: • Horizontal Reheat Replacement (\$5,053,000) • SCR Reactor Catalyst Replacement (\$2,000,000) • Nine additional projects totaling \$2,419,020	2023 actual expenditure: \$0 The precise value reported in CECo's filing is negative (-\$1,479,000). This is likely due to accounting treatment. For purposes of this analysis, I treat negative investment as \$0.	\$16,686,700
2024 projected spend (in 2021): \$21,005,000 \$9,753,000 at Campbell Unit 1, including: • Replace Burners Corner 1-8 (\$2,700,000) • Replace Air Preheater Baskets and Seals (\$1,137,100) • Boiler Component Replacement (\$3,000,000) • Balance of Plant Equipment Replacement (\$1,500,000) • Six additional projects totaling \$1,415,900 \$11,252,000 at Campbell Unit 2, including: • Horizontal Reheat Replacement (\$7,952,000) • Distributed Control System and Simulator Upgrade (\$1,500,000) • Four additional projects totaling \$1,800,000	2024 actual expenditure: \$0 The precise value reported in CECo's filing is negative (-\$1,510,000). This is likely due to accounting treatment. For purposes of this analysis, I treat negative investment as \$0, which is consistent with 2024 testimony from CECo witness Blumenstock stating that the company did not plan to invest any capital in the Campbell units in 2024. ¹⁴	\$21,005,000
2025 projected spend (in 2021): \$10,350,000 \$2,550,000 at Campbell Unit 1, including four projects that do not exceed \$669,000 individually \$7,800,000 at Campbell Unit 2, including: • Replace turbine right side Reheat Stop Valve body (\$1,850,000) • Boiler Component Replacement (\$3,000,000) • Five additional projects totaling \$2,950,000	2025 projected expenditure: \$0 CECo projected no capital expenditures at Unit 1 or Unit 2 in 2025.	\$10,350,000
	TOTAL	\$56,531,200

¹⁴ See U-21585, Blumenstock Direct Testimony, p. 62.

21. Table 4b compares the capital projects CECo proposed carrying out for Unit 3 before deciding to retire that unit in May 2025 with those projects CECo has actually carried out, or plans to carry out, after making that retirement decision. Capital spending dropped by more than half on Unit 3 in 2022, from a proposed \$17.1 million to \$7.9 million, and dropped almost entirely in 2023, from a proposed \$20.5 million to less than \$0.5 million. No capital spending occurred in 2024, and no capital spending has yet occurred or is expected to occur in 2025 as of CECo's June 2025 rate case filing. Cancelled Unit 3 capital projects with a direct impact on unit reliability include, among others, complete coal mill overhauls, boiler wall panel replacements, and fuel handling repairs.

Table 4b. Unit 3 Capital Spend: CECo pre-IRP projection vs. post-IRP actuals/projections

Pre-IRP projection	Post-IRP actuals/projections	Difference
2022 projected spend (in 2021): \$17,125,333 • PJFF Bag & Cleaning Air Manifold Replacement (\$3,994,601) • SCR Reactor Catalyst Management (\$1,866,200) • Complete Mill Overhauls (\$1,264,800) • Replace CO-O2 Monitors (\$967,400) • Design and Install New Large Particle Ash Screen (\$1,485,100) • Fuel Handling & Infrastructure Repairs (\$1,500,000) • Sixteen additional projects totaling \$6,047,032	2022 actual expenditure: \$7,935,000 The 2022 actual capital expenditure included three projects: air compressor replacement (\$1,207,000); selective catalytic reduction catalyst management (\$1,196,000); and diesel generator controls (\$1,172,000). The actual expenditure represented about 46 percent of the pre-IRP projection.	\$9,190,333
2023 projected spend (in 2021): \$20,478,187 • PJFF Bag & Cleaning Air Manifold Replacement (\$3,263,331) • Complete Mill Overhauls (\$1,295,300) • Design and Install New Large Particle Ash Screen (\$1,008,700) • Secondary Air Heater basket & seal replacement (\$2,425,000) • High Pressure Feedwater Heater 8A replacement (\$5,039,800) • Fuel Handling & Infrastructure Repairs (\$1,500,000) • Seventeen additional projects totaling \$6,954,257	2023 actual expenditure: \$456,000 The actual capital expenditure represented about 2 percent of the pre-IRP projection.	\$20,022,187
2024 projected spend (in 2021): \$33,395,569 • SCR Reactor Catalyst Management (\$1,959,510) • Turbine Drain Modifications (\$2,535,000) • Superheat Terminal Drain Replacement (\$3,023,100) • Replace Boiler Sidewall Panels (\$2,425,000) • Replace Boiler Front And Rear Wall Panels (\$2,482,900) • Secondary Air Heater basket & seal replacement (\$1,562,000) • Fuel Handling & Infrastructure Repairs (\$1,500,000) • Cell Construction and Permitting (\$5,482,830) • and twenty-one additional projects totaling \$12,425,229	2024 actual expenditure: \$0 The precise value reported in Consumers' filing is negative (-\$1,264,000). This is likely due to accounting treatment. For purposes of this analysis, I treat negative investment as \$0, which is consistent with 2024 testimony from CECo witness Blumenstock stating that the company did not plan to invest any capital in the Campbell units in 2024.	\$33,395,569
2025 projected spend (in 2021): \$14,512,045 • GSU Replacement (\$6,485,045) • SCR Reactor Catalyst Management (\$3,000,000) • AQCS Equipment repair/replacement (\$1,000,000) • Cell Construction and Permitting (\$2,000,000) • and four additional projects totaling \$2,027,000	2025 projected expenditure: \$0 CECo projected no Unit 3 capital budget in 2025.	\$14,512,045
	TOTAL	\$77,120,134

22. A detailed listing of the 2022-2025 major maintenance projects that CEC Co projected carrying out before deciding in 2022 to retire the units in May 2025 is shown in the left-hand column of Tables 5a (Units 1 and 2) and 5b (Unit 3).¹⁵ As can be seen from the middle column in these tables,¹⁶ CEC Co did not carry out most of those projects.

23. Table 5a compares the major maintenance projects CEC Co proposed carrying out for Units 1 and 2 before deciding to retire those units in May 2025 with those projects CEC Co has actually carried out, or plans to carry out, after making that retirement decision. Major maintenance spending declined by a total of 62 percent across 2022-2025, from a proposed total of \$14.4 million to \$5.5 million. CEC Co does not specify the nature of most of its major maintenance projects in its rate case filings. However, one cancelled major maintenance project with a direct impact on unit reliability is the Unit 2 turbine valve inspection project.

¹⁵ Information in the left-hand column is from witness Kapala's testimony in CEC Co's 2021 IRP case. See Michigan PSC Case No. U-21090, Revised Direct Testimony of Norman J. Kapala, pp. 28-30 (Oct. 2021).

¹⁶ Information in the middle column is from witness Blumenstock's testimony in CEC Co's 2023-2025 rate cases. See Ex. A-41 to the Direct Testimony of Richard T. Blumenstock in Michigan PSC Case No. U-21389 (May 2023) and Ex. A-43 to witness Blumenstock's testimony in Case Nos. U-21585 (May 2024), and U-21870 (June 2025).

Table 5a. Units 1&2 Major Maintenance Spend: CECo pre-IRP projection vs. post-IRP actuals/projections

Pre-IRP projection	Post-IRP actuals/projections	Difference
2022 projected spend (in 2021): \$3,537,000 - Campbell 1 and 2 Periodic Outage Maintenance (\$1,248,000) - Thirteen additional projects totaling \$2,289,000	2022 actual expenditure: \$3,307,000 The 2022 actual maintenance expenditure was slightly less than the Unit 1&2 maintenance budget projected by CECo in 2021.	\$230,000
2023 projected spend (in 2021): \$2,905,000 Covering 10 projects	2023 actual expenditure: \$1,054,000 The 2023 actual maintenance expenditure was approximately one-third the Unit 1&2 maintenance budget proposed for 2023 by CECo in 2021.	\$1,851,000
2024 projected spend (in 2021): \$3,405,167 Covering 12 projects	2024 actual expenditure: \$903,000 The 2024 actual maintenance expenditure was approximately 27 percent of the Unit 1&2 maintenance budget proposed for 2024 by CECo in 2021.	\$2,502,167
2025 projected spend (in 2021): \$4,569,000 - Campbell 2 Turbine Valve Inspection (\$1,300,000) - Seven additional projects totaling \$3,269,000	2025 projected expenditure:¹⁷ \$268,000 The 2025 projected maintenance expenditure was approximately 6 percent of the Unit 1&2 maintenance budget proposed for 2025 by CECo in 2021.	\$4,301,000
	TOTAL	\$8,884,167

¹⁷ See U-21585, Ex. A-43 to Blumenstock Direct Testimony. This exhibit shows the “Projected Test Year 12 Months Ending 02/28/26.” This 12-month cost projection covers most of the 5-month 2025 operational period (1/1/25 – 5/31/25) for Campbell Units 1&2 as well as the additional months those units would not be operational. From the information I reviewed, this is the best source of information regarding CECo’s actual and projected 2025 major maintenance spending.

24. Table 5b compares the major maintenance projects CECo proposed carrying out for Unit 3 before deciding to retire that unit in May 2025 with those projects CECo has actually carried out, or plans to carry out, after making that retirement decision. Major maintenance spending declined by a total of 78 percent across 2022-2025, from a proposed total of \$23.5 million to \$5.1 million. CECo does not specify most of its major maintenance projects in its rate case filings. However, as discussed in more detail below, one cancelled major maintenance project with a direct impact on unit reliability is the \$7.9 million Unit 3 turbine overhaul project. The project was originally scheduled to take place in 2024. The turbine failed in April 2024 resulting in a 46-day forced outage.¹⁸

¹⁸ See *infra* Tbl. 1.

Table 5b. Unit 3 Major Maintenance Spend: CECo pre-IRP projection vs. post-IRP actuals/projections

Pre-IRP projection	Post-IRP actuals/projections	Difference
2022 projected spend (in 2021): \$4,208,040 - Boiler Feed Pump Turbine Inspection (\$1,680,000) - Fourteen additional projects totaling \$2,528,040	2022 actual expenditure: \$3,196,000 The 2022 actual maintenance expenditure was sufficient to do about 75 percent of the Unit 3 maintenance projects budgeted for 2022 by CECo in 2021.	\$1,012,040
2023 projected spend (in 2021): \$2,523,970 Covering 12 projects	2023 actual expenditure: \$995,000 The actual expenditure represented about 40 percent of the pre-IRP projection.	\$1,528,970
2024 projected spend (in 2021): \$12,954,250 - Campbell 3 Turbine Overhaul (\$7,931,350) - Campbell 3 Boiler Chemical Cleaning (\$1,429,000) - Campbell 3 Base Outage Boiler and Critical Maintenance (\$1,000,000) - Campbell 3 Periodic Outage Maintenance (\$933,100) - Eight additional projects totaling \$1,660,800	2024 actual expenditure: \$591,000 The 2024 projected actual maintenance expenditure was sufficient to do about 5 percent of the Unit 3 maintenance projects budgeted for 2024 by CECo in 2021. The highest cost proposed 2024 project, the Campbell 3 Turbine Overhaul (\$7,931,350), was not carried out. The turbine failed in April 2024 resulting in a 46-day forced outage.	\$12,363,250
2025 projected spend (in 2021): \$3,810,600 - Campbell 3 Turbine Valve Inspection (\$1,200,000) - Campbell 3 Base Outage Boiler and Critical Maintenance (\$1,100,000) - Six additional projects totaling \$1,410,600	2025 projected expenditure:¹⁹ \$277,000 The actual expenditure represented about 7 percent of the pre-IRP projection.	\$3,533,600
	TOTAL	\$18,437,860

¹⁹ See U-21585, Ex. A-43 to Blumenstock Direct Testimony. This exhibit shows the “Projected Test Year 12 Months Ending 02/28/26.” This 12-month cost projection covers most of the 5-month 2025 operational period (1/1/25 – 5/31/25) for Campbell Unit 3 as well as the additional months that unit would not be operational. From the information I reviewed, this is the best source of information regarding CECo’s actual and projected 2025 major maintenance spending.

25. It is unlikely that Campbell can reliably dispatch given this deferred capital and major maintenance spending.

26. Moreover, Campbell Units 1 and 2 were built in the 1960s. Units 1 and 2 are beyond both a typical coal unit economic design life of 30-40 years and a typical operational lifetime of 40-50 years.^{20,21}

27. Replacement parts are not readily available or do not exist for Units 1 and 2, as described by CEC Co witness Hoffman: “Some of these units were built in the 1960s, and given the ages and designs of the systems, replacement parts are not always readily available. In some instances, replacement parts do not exist at all. The start-up boiler feed pump (“SUBFP”) at Campbell Unit 2 is one of those systems. Keeping spare parts on hand is neither cost effective nor practical since replacements do not exist.”²²

28. CEC Co witness Blumenstock states that CEC Co discontinued capital investment in Units 1-3 in 2023 and is only doing sufficient maintenance to keep Units 1-3 operable through May 2025: “The Company does not plan to invest any capital in the Campbell units during the bridge period [2024 and early 2025] or test year . . . [T]he Company has projected modest amounts of major maintenance to ensure that these units are able to operate through their retirement date of May 31, 2025.”²³ Witness Blumenstock also indicates that Unit 1 would be retired early, on April 1, 2025.²⁴

29. In my professional opinion, witness Blumenstock is describing CEC Co’s transition from a preventative capital investment and maintenance structure, intended to maintain the

²⁰ M. Hafner, G. Luciani, *The Palgrave Handbook of International Energy Economics*, p. 127 (2022).

²¹ International Energy Agency, *The role of CCUS in low-carbon power systems*, p. 18 (2020).

²² U-21424, Hoffman Direct Testimony, p.6.

²³ U-21585, Blumenstock Direct Testimony, p. 62.

²⁴ *Ibid.*, p. 20.

Campbell units' long-term reliability, to a reactive, "fix it if breaks" approach to operating Units 1-3. CECo's objective shifted from maintaining long-term reliability to keeping the units operating—to the extent possible with little or no spending—*up until May 31, 2025 and no longer*. CECo's objective was *not* to achieve the high level of Unit 1-3 reliability that would be necessary for the units to ramp up and work reliably under emergency demand conditions.

30. A case in point is the cancelled \$7.9 million Unit 3 turbine overhaul project that was originally scheduled for 2024.²⁵ In late April 2024, the Unit 3 turbine suffered a turning gear failure that resulted in a 1,104-hour (46 day) forced outage.²⁶ The turbine turning gear was repaired to achieve the limited objective of allowing Unit 3 to continue to operate until the planned retirement in (May) 2025.²⁷ It is reasonable to assume that the turning gear failure would not have occurred if the Unit 3 turbine had already been overhauled. This failure incident calls into question how many other Unit 3 components are vulnerable to near-term failure due to lack of investment and preventative maintenance by CECo. Given the limited maintenance, it would be unreasonable for DOE to assume that Unit 3 can run much longer without CECo doing a substantial amount of deferred maintenance.

31. While it is not possible based on publicly available information to put an exact price tag on the cost of ensuring that Campbell could reliably operate at full capacity, CECo cancelled **approximately \$161 million** in planned capital and major maintenance projects at Campbell over the past four years (\$133.6 million in capital projects; \$27.3 million in major maintenance projects). It is reasonable to assume that much of this investment was necessary to ensure continued, nominally reliable operation of Campbell. It is also reasonable to assume that

²⁵ U-21090, Kapala Revised Direct Testimony, p. 29.

²⁶ U-21424, Ex. A-11 to Hoffman Direct Testimony.

²⁷ *Ibid.*, Ex. A-13.

some of this investment was necessary to ensure compliance with environmental requirements, as discussed more below. Those capital and major maintenance investments are what *CECo determined* in 2021 that it would need to spend on a year-to-year basis to operate the Campbell units reliably and in conformance with environmental requirements in 2022-2025, if these units were to continue to operate past May 2025 (i.e. until 2031 for Units 1 and 2 and until 2039 for Unit 3).

B. Whether Campbell can operate effectively as a peaking unit

32. In my opinion, Campbell cannot operate effectively as a peaking unit that would be dispatched with only a few hours of notice to meet an extreme demand condition.

33. Coal units generally, and Campbell’s three units specifically, cannot serve as peaking units that respond to extreme peak demand on short notice. Coal units are designed for baseload, round-the-clock operation.²⁸ Coal units started “cold” (room temperature) typically take approximately 12 hours to reach full load operation.²⁹ The ramp rate is slow to avoid excessive thermal stress on components exposed to heat. In contrast, utility-scale battery storage can dispatch from a cold start to full power in a matter of seconds.³⁰ Similarly, combustion gas turbines, designed for fast-response peaking duty, can go from a cold start to full power in 5 to 10 minutes.³¹

34. Coal units cannot respond to extreme demand events unless they are fully online several hours before the high demand situation occurs. In other words, coal units need

²⁸ U-21258, Hoffman Direct Testimony, pp. 4-5.

²⁹ IEA Clean Coal Centre, *Increasing the flexibility of coal-fired power plants*, p. 26 (Sept. 2014).

³⁰ NERC, *Energy Storage: Overview of Electrochemical Storage*, p. 1 (Feb. 2021).

https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Master_ESAT_Report.pdf (“BESS are a well suited technology to provide short-term grid contingency support (tens of seconds) . . .”).

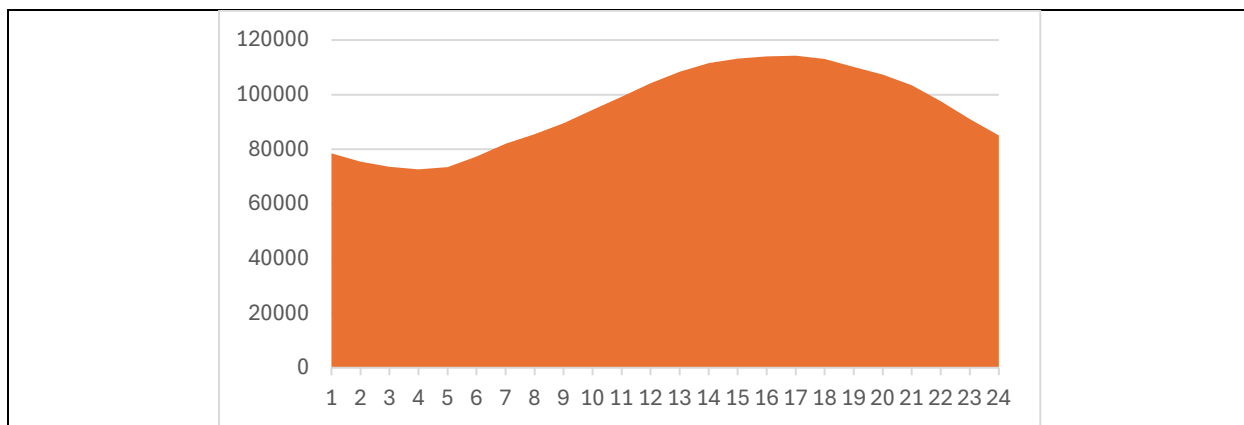
³¹ General Electric, *Get to know the LM6000* (webpage) (2025), <https://www.gevernova.com/gas-power/products/gas-turbines/lm6000>. (“With around five minutes to ramp up from start-up to full power . . .”).

substantial lead time to be fully operational at or before an extreme peak demand is reached.

They cannot be dispatched from an offline “cold” status to address extreme emergency demand if an emergency is declared only a few hours before the demand must be met.

35. Grid demand often increases rapidly on peak demand days. MISO may have only a few hours of notice that an extreme peak demand day is developing. The need to bring on additional generation resources to meet an extreme peak may be uncertain until the period immediately prior to the actual peak. An example of this can be seen in Figure 1, which shows a 24-hour demand curve for the MISO control area on the high demand summer day of September 5, 2023.³² MISO actual demand was rising as fast as 5,000 MW per hour during the day, adding the equivalent of Campbell’s 1,561 MW capacity every 20 minutes to meet demand.

Figure 1. MISO 24-hour demand curve (MW), September 5, 2023



36. Bringing Campbell from a cold start condition to full output to meet extreme demand would also be expensive. According to the National Association of Regulatory Utility Commissioners, the estimated cost to “cold start” a coal-fired power plant is \$417 per MW of capacity.³³ The total nameplate capacity of Campbell Units 1-3 is 1,561 MW. Therefore, the

³² Figure 1 was developed using data from U.S. EIA, csv dataset, “MISO_load-temp_hr_2023” (accessed June 13, 2025).

³³ NARUC, *Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices*, p. 16 (Jan. 2020).

estimated cost to start up Campbell from a cold start condition would be approximately \$650,000. (1,561 MW × \$417 per MW = \$650,937).

37. Alternatively, instead of starting cold, CECo could be forced to run Campbell for hours unnecessarily solely to be prepared for a potential near-term high-peak demand. That approach would be expensive and polluting.

C. Easily attainable steps DOE can require to ensure Campbell's operations are consistent with environmental requirements and minimize adverse environmental impacts

38. In my opinion, for DOE's order to be consistent with environmental requirements, CECo must demonstrate, prior to restarting Units 1-3, that (1) the pulse jet fabric filters on Units 1-3 are in sound, leak-free condition, and (2) the SCRs on Units 2 and 3 have sufficient remaining catalyst life to adequately control NO_x emissions.

39. As noted above, some of the capital and major maintenance projects cancelled in 2022-2025 were air emission control system projects. Cancelled capital projects with a direct impact on maintaining environmental compliance included, among others, PJFF filter bag(s) replacement on Unit 1 (for particulate/opacity control); SCR reactor catalyst replacement on Unit 2 (for nitrogen oxide control); and replacement of PJFF filter bag(s), "cleaning air manifold," and SCR reactor catalyst on Unit 3.³⁴ These projects were planned likely because CECo believed they were necessary to maintain adequate air emission control system performance and that failure to carry out the projects could compromise that performance.

40. Table 6 shows the multiple air emission control system capital projects that were cancelled in 2022-2025. The implications of these cancelled air quality control system projects are: (1) degraded fabric filter performance on Units 1 and 3, potentially resulting in particulate

³⁴ See *infra* Tables 4a and 4b.

and/or opacity exceedances, and (2) degraded performance of nitrogen oxide (NO_x) control systems (SCR) on Units 2 and 3, potentially resulting in NO_x exceedances. Degraded fabric filter performance, caused by torn or improperly secured filter bags, could lead to elevated levels of opacity and particulate emissions. A degraded SCR catalyst could lead to poor NO_x conversion and elevated NO_x emissions at the stack.

Table 6. Cancelled 2022-2025 Campbell Unit 1-3 air quality control capital projects

Year	Unit	Project ³⁵	Budget (\$)
2022	2	• (SCR) catalyst management	1,120,000
	3	• Fabric filter bag(s) & cleaning air manifold replacement	3,994,601
2023	1	• Fabric filter bag replacement	1,514,100
	2	• SCR reactor catalyst replacement	2,000,000
	3	• Fabric filter bag(s) & cleaning air manifold replacement	3,263,331
2025	3	• SCR reactor catalyst management	3,000,000
		• Air quality control system (AQCS) equipment repair/replacement	1,000,000

41. In light of these cancelled projects, DOE should require that CECo demonstrate that the Campbell Unit 1-3 pulse jet fabric filters are currently leak free prior to authorizing further operation. DOE also should require that CECo provide records demonstrating that the catalysts in the Units 2 and 3 SCRs have sufficient remaining useful life to reasonably assure compliance with NO_x limits.

42. It is my opinion that DOE should require verification of the good working order of the Unit 1-3 air emission control systems before authorizing Campbell to operate under extreme demand conditions. DOE should also require that any Campbell unit that exceeds air permit limits for opacity, NO_x, or SO₂ that occur during operation of Units 1-3, as registered on the continuous opacity, NO_x, or SO₂ monitors installed on each unit, be shut down.

³⁵ See U-21090, Kapala Revised Direct Testimony; U-21389, Blumenstock Direct Testimony, Ex. A-12 (not listed as carried-out); U-21585, Blumenstock Direct Testimony, A-12 (not listed as carried-out).

43. It is also my opinion that there are alternatives to running Campbell to meet an extreme peak demand that would produce far less environmental harm.

44. Any air emissions that result from running Campbell would not occur if the plant is retired. Additionally, according to its NPDES wastewater discharge permit, Campbell is cooled with ~1 billion gallons per day of Lake Michigan water in a once-through cooling configuration (NPDES permit). Therefore, the plant will use up to 1 billion gallons per day if called to operate. That is a potentially significant impact on Lake Michigan marine fauna that does not occur if Campbell is retired. Finally, any coal burned will produce coal ash that will have to be stored/disposed of onsite. That is another impact that would not occur if Campbell is retired.

45. In my opinion, a coal unit would be the last alternative to consider for a peaking power application due to its slow ramp time and high environmental impact.

I declare under penalty of perjury under the laws of the United States, pursuant to 28 U.S.C. § 1746, that the foregoing is true and correct to the best of my knowledge.

Executed on this 15th day of June 2025, in San Diego, California.



Bill Powers, P.E.
Powers Engineering
4452 Park Blvd., Suite 209
San Diego, CA 92116

Attachment A

BILL POWERS, P.E.

PROFESSIONAL HISTORY

Powers Engineering, San Diego, CA 1994-
ENSR Consulting and Engineering, Camarillo, CA 1989-93
Naval Energy and Environmental Support Activity, Port Hueneme, CA 1982-87
U.S. Environmental Protection Agency, Research Triangle Park, NC 1980-81

EDUCATION

Bachelor of Science – Mechanical Engineering, Duke University
Master of Public Health – Environmental Sciences, University of North Carolina

PROFESSIONAL AFFILIATIONS

Registered Professional Mechanical Engineer, California (Certificate M24518)
Registered Professional Engineer, Missouri (Certificate 2018039156)
American Society of Mechanical Engineers
Institute of Electrical and Electronics Engineers

TECHNICAL SPECIALTIES

Forty years of experience in:

- Air quality and utility commission proceedings - expert witness
- Distributed solar photovoltaics (PV) siting and regional renewable energy planning
- Power plant cooling system conversion and air emission control assessments
- Combustion equipment permitting, testing and monitoring
- Air pollution control equipment retrofit design/performance testing
- Petroleum refinery air engineering and testing
- Latin America environmental project experience

RECENT AIR QUALITY AND UTILITY COMMISSION PROCEEDINGS

Compressor Station Gas Turbine Air Emission Controls. Assessed the air emission controls and siting issues related to two proposed pipeline compressor station projects in the vicinity of Nashville, Tennessee utilizing Solar Turbines, Inc Titan gas turbines. The result, based on application of a Reasonably Available Control Technology (RACT) requirement, was the reduction of the proposed air permit nitrogen oxides (NO_x) emission limit from 25 parts per million (ppm) to 9 ppm.

Combined Heat and Power Plant Gas Turbine Air Emission Controls. Evaluated the air emission controls proposed for a combined heat and power (CHP) plant at Duke University that would utilize Solar Turbines, Inc Titan gas turbine. Applicant proposed a 25 ppm NO_x limit using dry low-NO_x combustion as Best Available Control Technology (BACT) in its Certificate of Public Convenience and Necessity (CPCN) application to the North Carolina Utilities Commission. Argued that NO_x BACT for the CHP plant should be use of selective catalytic reduction (SCR) to achieve a 2 ppm NO_x emission limit. Applicant withdrew its CPCN application.

SDG&E 36-Inch Transmission Pipeline. Expert witness for non-profit client advocating that existing 16-inch pipeline did not require replacement with new \$600 million 36-inch pipeline. Underscored in testimony that SDG&E had recently completed extensive inline inspection of existing 16-inch pipeline and found that pipeline was in good condition for long-term operation at 512 psig transmission pressure. Demonstrated that reduction of pressure to 320 psig would not increase safety of existing pipeline, as ILI could no longer be done periodically at lower pressure. Commission accepted this reasoning and denied SDG&E's application.

Cove Point LNG Export Terminal. Expert witness in two separate administrative proceedings before the Maryland Public Service Commission, in 2014 and 2017, regarding air permit conditions for the proposed Cove Point LNG export. The plant site is located in a non-attainment area for ozone. Testimony addressed deficiencies in the proposed air emission limits and proposed control technology for combustion equipment – including gas turbines, auxiliary boilers, and flares, fugitive emission sources, and marine loading vapor recovery systems.

Corpus Christi LNG Export Terminal. Expert witness in Texas Commission on Environmental Quality contested air permit proceeding in 2013 before the State Office of Administrative Hearings. Testimony addressed deficiencies in the proposed control technology for compressor-drive gas turbines, flares, and fugitive emission sources, and marine loading vapor recovery systems.

DISTRIBUTED SOLAR PV SITING AND REGIONAL RENEWABLE ENERGY PLANNING

Roadmap to 100 Percent Local Solar by 2030 in the City of San Diego. Author of the May 2020 *Roadmap to 100 Percent Local Solar Build-Out by 2030 in the City of San Diego* strategic energy plan for San Diego. The *Roadmap* outlines a strategy to maximize the use of solar energy and battery storage in the City of San Diego (City) to provide 100 percent clean electricity to all San Diegans by 2030. The City’s Climate Action Plan sets a mandatory target of 100 percent clean electricity by 2035. The *Roadmap* describes how the City can best deliver lower-cost electricity and provide local job growth by choosing local solar power paired with battery storage, complemented by smart energy efficiency and demand response programs, to reach 100 percent clean energy.

North Carolina Clean Path 2025 Plan. Author of the August 2017 *North Carolina Clean Path 2025* strategic energy plan for North Carolina. *NC Clean Path 2025* implements local solar power, battery storage, and energy efficiency measures to rapidly replace fossil fuel-generated electricity in the state. The plan is substantially less costly than the \$40 billion expansion of natural gas infrastructure, nuclear power, and transmission infrastructure being planned for North Carolina. Implementation of *NC Clean Path 2025* would reduce power generated by coal- and natural gas-fired plants by about 60 percent by 2025, and 100 percent by 2030. All in-state coal-fired plants would be closed and gas-fired plants would be used only for backup supply. Existing transmission and distribution infrastructure would be maintained and not expanded.

Bay Area Smart Energy 2020 Plan. Author of the March 2012 *Bay Area Smart Energy 2020* strategic energy plan for the nine-county region surrounding San Francisco Bay. This plan uses the zero net energy building targets in the *California Energy Efficiency Strategic Plan* as a framework to achieve a 60 percent reduction in GHG emissions from Bay Area electricity usage, and a 50 percent reduction in peak demand for grid electricity, by 2020. The 2020 targets in the plan include: 25 percent of detached homes and 20 percent of commercial buildings achieving zero net energy, adding 200 MW of community-scale microgrid battery storage and 400 MW of utility-scale battery storage, reduction in air conditioner loads by 50 percent through air conditioner cycling and targeted incentive funds to assure highest efficiency replacement units, and cooling system modifications to increase power output from The Geysers geothermal production zone in Sonoma County.

Solar PV technology selection and siting for SDG&E Solar San Diego project. Served as PV technology expert in California Public Utilities Commission proceeding to define PV technology and sites to be used in San Diego Gas & Electric (SDG&E) \$250 million “Solar San Diego” project. Recommendations included: 1) prioritize use of roof-mounted thin-film PV arrays similar to the SCE urban PV program to maximize the installed PV capacity, 2) avoid tracking ground-mounted PV arrays due to high cost and relative lack of available land in the urban/suburban core, 3) and incorporate limited storage in fixed rooftop PV arrays to maximizing output during peak demand periods. Suitable land next to SDG&E substations capable of supporting 5 to 40 MW of PV (each) was also identified by Powers Engineering as a component of this project.

Rooftop PV alternative to natural gas-fired peaking gas turbines, Chula Vista. Served as PV technology expert in California Energy Commission (CEC) proceeding regarding the application of MMC Energy to build a 100 MW peaking gas turbine power plant in Chula Vista. Presented testimony that 100 MW of PV arrays in the Chula Vista area could provide the same level of electrical reliability on hot summer days as an equivalent amount of peaking gas turbine capacity at approximately the same cost of energy. The final decision issued by the CEC in the case denied the application in part due to failure of the applicant or CEC staff to thoroughly evaluate the PV alternative to the proposed turbines.

San Diego Smart Energy 2020 Plan. Author of October 2007 *San Diego Smart Energy 2020*, an energy plan that focuses on meeting the San Diego region's electric energy needs through accelerated integration of renewable and non-renewable distributed generation, in the form of combined heat and power (CHP) systems and solar photovoltaic (PV) systems. PV would meet approximately 28 percent of the San Diego region's electric energy demand in 2020. Annual energy demand would drop 20 percent in 2020 relative to 2003 through use all cost-effective energy efficiency measures. Existing utility-scale gas-fired generation would continue to be utilized to provide power at night, during cloudy weather, and for grid reliability support.

COOLING SYSTEM CONVERSION AND POWER PLANT EMISSION CONTROL ASSESSMENTS

Closed-Cycle Cooling Alternative at California Nuclear Plant.

Lead engineer on review of Bechtel assessment of wedgewire screens and closed-cycle cooling for Diablo Canyon nuclear plant. Demonstrated that wedgewire screens were not likely to be effective in substantially reducing entrainment at the site, and that lower cost closed-cycle retrofit alternatives could be utilized to allow a "cost reasonable" cooling tower retrofit. Plume-abated back-to-back cooling towers located in secondary parking lots to the southeast of the turbine building were identified as the most cost-effective alternative.

Closed-Cycle Cooling Alternative at Florida Nuclear Plant.

Evaluated closed cycle cooling tower feasibility assessment for Turkey Point Nuclear Units 3 and 4. Closed-cycle cooling would replace the existing closed-cycle cooling canals. Wet cooling towers for Units 3 and 4 are feasible and could be operational within four years of submittal of applications for the necessary permits.

Utility Boilers – Conversion of Existing Once-Through Cooled Boilers to Wet Towers, Parallel Wet-Dry Cooling, or Dry Cooling. Provided expert testimony and preliminary design for the conversion of four natural gas and/or coal-fired utility boilers (Unit 4, 235 MW; Unit 3, 135 MW; Unit 2, 65 MW; and Unit 1, 65 MW) from once-through river water cooling to wet cooling towers, parallel wet-dry cooling, and dry cooling. Major design constraints were available land for location of retrofit cooling systems and need to maintain maximum steam turbine backpressure at or below 5.5 inches mercury to match performance capabilities of existing equipment. Approach temperatures of 12 °F and 13 °F were used for the wet towers. SPX Cooling Technologies F-488 plume-abated wet cells with six feet of packing were used to achieve approach temperatures of 12 °F and 13 °F. Annual energy penalty of wet tower retrofit designs is approximately 1 percent. Parallel wet-dry or dry cooling was determined to be technically feasible for Unit 3 based on straightforward access to the Unit 3 surface condenser and available land adjacent to the boiler.

Utility Boiler – Assessment of Air Cooling and Integrated Gasification/Combined Cycle for Proposed 500 MW Coal-Fired Plant. Provided expert testimony on the performance of air-cooling and IGCC relative to the conventional closed-cycle wet cooled, supercritical pulverized coal boiler proposed by the applicant. Steam Pro™ coal-fired power plant design software was used to model the proposed plant and evaluate the impacts on performance of air cooling and plume-abated wet cooling. Results indicated that a conservatively designed air-cooled condenser could maintain rated power output at the design ambient temperature of 90 °F. The IGCC comparative analysis indicated that unit reliability comparable to a conventional pulverized coal unit could be achieved by including a spare gasifier in the IGCC design, and that the slightly higher capital cost of IGCC was offset by greater thermal efficiency and reduced water demand and air emissions.

Utility Boiler – Assessment of Closed-Cycle Cooling Retrofit Cost for 1,200 MW Oil-Fired Plant.

Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 1,200 MW Roseton Generating Station. Determined that the cost to retrofit the Roseton plant with plume-abated closed-cycle wet cooling was well established based on cooling tower retrofit studies performed by the original owner (Central Hudson Gas & Electric Corp.) and subsequent regulatory agency critique of the cost estimate. Also determined that elimination of redundant and/or excessive budgetary line items in owners cost estimate brings the closed-cycle retrofit in line with expected costs for comparable new or retrofit plume-abated cooling tower applications.

Nuclear Power Plant – Assessment of Closed-Cycle Cooling Retrofit Cost for 2,000 MW Plant. Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 2,000 MW Indian Point Generating Station. Determined that the most appropriate arrangement for the hilly site would be an inline plume-abated wet tower instead of the round tower configuration analyzed by the owner. Use of the inline configuration would allow placement of the towers at numerous sites on the property with little or need for blasting of bedrock, greatly reducing the cost of the retrofit. Also proposed an alternative circulating cooling water piping configuration to avoid the extensive downtime projected by the owner for modifications to the existing discharge channel.

Power Plant Dry Cooling Symposium – Chair and Organizer. Chair and organizer of the first symposium held in the U.S. (May 2002) that focused exclusively on dry cooling technology for power plants. Sessions included basic principles of wet and dry cooling systems, performance capabilities of dry cooling systems, case studies of specific installations, and reasons why dry cooling is the predominant form of cooling specified in certain regions of North America (Massachusetts, Nevada, northern Mexico).

Ameren Missouri Coal Units – Causes of Opacity and Opacity Reduction Alternatives.

Lead engineer to assess the root causes of opacity exceedances and evaluate potential alternatives to eliminate opacity violations from the Labadie, Meramec, and Rush Island power plants.

Utility Boilers – Evaluation of Correlation Between Opacity and PM₁₀ Emissions at Coal-Fired Plant.

Provided expert testimony on whether correlation existed between mass PM₁₀ emissions and opacity during opacity excursions at large coal-fired boiler in Georgia. EPA and EPRI technical studies were reviewed to assess the correlation of opacity and mass emissions during opacity levels below and above 20 percent. A strong correlation between opacity and mass emissions was apparent at a sister plant at opacities less than 20 percent. The correlation suggests that the opacity monitor correlation underestimates mass emissions at opacities greater than 20 percent, but may continue to exhibit a good correlation for the component of mass emissions in the PM₁₀ size range.

IGCC as BACT for Air Emissions from Proposed 960 MW Coal Plant. Presented testimony on IGCC as BACT for air emissions reduction from 960 MW coal plant. Applicant received air permit for a pulverized coal plant to be equipped with a baghouse, wet scrubber, and wet ESP for air emissions control. Use of IGCC technology at the emission rates permitted for two recently proposed U.S. IGCC projects, and demonstrated in practice at a Japanese IGCC plant firing Chinese bituminous coal, would substantially reduce potential emissions of NO_x, SO₂, and PM. The estimated control cost-effectiveness of substituting IGCC for pulverized coal technology in this case was approximately \$3,000/ton.

Analysis of Proposed Air Emission Limits for 600 MW Pulverized Coal Plant. Project engineer tasked with evaluating sufficiency of air emissions limits and control technologies for proposed 600 MW coal plant Arkansas. Determined that the applicant had: 1) not properly identified SO₂, sulfuric acid mist, and PM BACT control levels for the plant, and 2) improperly utilized an incremental cost effectiveness analysis to justify air emission control levels that did not represent BACT.

Eight Pulverized Coal Fired 900 MW Boilers – IGCC Alternative with Air Cooling. Provided testimony on integrated gasification combined cycle (IGCC) as a fully commercial coal-burning alternative to the pulverized coal (PC) technology proposed by TXU for eight 900 MW boilers in East Texas, and East Texas as an ideal location for CO₂ sequestration due to presence of mature oilfield CO₂ enhanced oil recovery opportunities and a deep saline aquifer underlying the entire region. Also presented testimony on the major increase in regional consumptive water use that would be caused by the evaporative cooling towers proposed for use in the PC plants, and that consumptive water use could be lowered by using IGCC with evaporative cooling towers or by using air-cooled condensers with PC or IGCC technology. TXU ultimately dropped plans to build the eight PC plants as a condition of a corporate buy-out.

Utility Boilers – Retrofit of SCR and FGD to Existing Coal-Fired Units.

Expert witness in successful effort to compel an existing coal-fired power plant located in Massachusetts to meet an accelerated NO_x and SO₂ emission control system retrofit schedule. Plant owner argued the installation of advanced NO_x and SO₂ control systems would generate > 1 ton/year of ancillary emissions, such as sulfuric acid mist, and that under Massachusetts Dept. of Environmental Protection regulation ancillary emissions > 1 ton/year would require a BACT evaluation and a two-year extension to retrofit schedule. Successfully demonstrated that no ancillary emissions would be generated if the retrofit NO_x and SO₂ control systems were properly sized and optimized. Plant owner committed to accelerated compliance schedule in settlement agreement.

Utility Boilers – Retrofit of SCR to Existing Natural Gas-Fired Units.

Lead engineer in successful representation of interests of California coastal city to prevent weakening of an existing countywide utility boiler NO_x rule. Weakening of NO_x rule would have allowed a merchant utility boiler plant located in the city to operate without installing selective catalytic reduction (SCR) NO_x control systems. This project required numerous appearances before the county air pollution control hearing board to successfully defend the existing utility boiler NO_x rule.

Biomass Plant NO_x and CO Air Emissions Control Evaluation. Lead engineer for evaluation of available nitrogen oxide (NO_x) and carbon monoxide (CO) controls for a 45 MW Aspen Power biomass plant in Texas where proponent had identified selective non-catalytic reduction (SNCR) for NO_x and good combustion practices for CO as BACT. Identified the use of tail-end SCR for NO_x control at several operational U.S. biomass plants, and oxidation catalyst in use at two of these plants for CO and VOC control, as BACT for the proposed biomass plant. Administrative law judge concurred in decision that SCR and oxidation catalyst is BACT. Developer added SCR and oxidation catalyst to project in subsequent settlement agreement.

Biomass Plant Air Emissions Control Consulting. Lead expert on biomass air emissions control systems for landowners that will be impacted by a proposed 50 MW biomass to be built by the local East Texas power cooperative. Public utility agreed to meet current BACT for biomass plants in Texas, SCR for NO_x and oxidation catalyst for CO, in settlement agreement with local landowners.

Combined-Cycle Power Plant Startup and Shutdown Emissions. Lead engineer for analysis of air permit startup and shutdown emissions minimization for combined-cycle power plant proposed for the San Francisco Bay Area. Original equipment was specified for baseload operation prior to suspension of project in early 2000s. Operational profile described in revised air permit was load following with potential for daily start/stop. Recommended that either fast start turbine technology be employed to minimize start/stop emissions or that “demonstrated in practice” operational and control software modifications be employed to minimize startup/shutdown emissions.

NON-WIRES ALTERNATIVES TO TRANSMISSION LINES

Ameren Missouri Mark Twain 345 kV Transmission Line. Responsible for evaluating: 1) the expected peak load growth of Ameren Missouri (MO) in general and in Northeast MO specifically over the next decade, 2) the likelihood of wind projects moving forward in the Northeast MO over the next decade, 3) the feasibility and cost of reconductoring with high capacity composite conductors the three 161 kV line segments that would experience NERC violations if 450 to 500 MW of wind power was constructed in Northeast MO, and 4) the feasibility and cost-effectiveness of substituting local solar for wind power to allow Ameren MO to meet its 2021 Renewable Portfolio Standard (RPS) obligation without building the proposed 345 kV transmission line or upgrading the three existing 161 kV lines interconnecting at the Adair Substation.

American Transmission Corporation Badger-Coulee 345 kV Line. Responsible for evaluating: 1) the expected peak load growth of Wisconsin utilities over the next decade, and 2) the feasibility and cost-effectiveness of alternatives including load management, energy efficiency, local solar, biogas, and energy storage as viable no-wires alternatives to the proposed ATC Badger-Coulee 345 kV transmission line.

San Diego Gas & Electric Wood Pole to Steel Pole Replacement Project.

Lead engineer assessing need and alternatives to replacement of existing wooden 69 kV poles with larger steel 69 kV poles as a response to the fire hazard potential of wooden poles in rural, high fire risk areas. Wooden poles in good condition and not a source of fire ignition. Utility would continue to shut off power to customers during low humidity, high wind conditions. Prepared alternative, solar with batteries for the ~10,000 affected customer meters, to allow customers to ride-through high fire hazard preventive grid power shut-offs at far less cost than replacing wood poles with steel poles.

San Diego Gas & Electric 500 kV Sunrise Transmission Line.

Lead engineer assessing the validity of load growth forecasts used by the utility to justify the need for the 500 kV line, and for developing a no-wires alternative, net-metered solar power with some battery support, to meet the identified reliability need at little or no net cost to the utility customer base.

COMBUSTION EQUIPMENT PERMITTING, TESTING AND MONITORING

EPRI Gas Turbine Power Plant Permitting Documents – Co-Author.

Co-authored two Electric Power Research Institute (EPRI) gas turbine power plant siting documents. Responsibilities included chapter on state-of-the-art air emission control systems for simple-cycle and combined-cycle gas turbines, and authorship of sections on dry cooling and zero liquid discharge systems.

Air Permits for 50 MW Peaker Gas Turbines – Six Sites Throughout California.

Responsible for preparing all aspects of air permit applications for five 50 MW FT-8 simple-cycle turbine installations at sites around California in response to emergency request by California state government for additional peaking power. Units were designed to meet 2.0 ppm NO_x using standard temperature SCR and innovative dilution air system to maintain exhaust gas temperature within acceptable SCR range. Oxidation catalyst is also used to maintain CO below 6.0 ppm.

Kauai 27 MW Cogeneration Plant – Air Emission Control System Analysis. Project manager to evaluate technical feasibility of SCR for 27 MW naphtha-fired turbine with once-through heat recovery steam generator. Permit action was stalled due to questions of SCR feasibility. Extensive analysis of the performance of existing oil-fired turbines equipped with SCR, and bench-scale tests of SCR applied to naphtha-fired turbines, indicated that SCR would perform adequately. Urea was selected as the SCR reagent given the local availability of urea. Unit is first known application of urea-injected SCR on a naphtha-fired turbine.

Microturbines – Ronald Reagan Library, Ventura County, California.

Project manager and lead engineer on preparation of air permit applications for microturbines and standby boilers. The microturbines drive the heating and cooling system for the library. The microturbines are certified by the manufacturer to meet the 9 ppm NO_x emission limit for this equipment. Low-NO_x burners are BACT for the standby boilers.

Hospital Cogeneration Microturbines – South Coast Air Quality Management District.

Project manager and lead engineer for preparation of air permit application for three microturbines at hospital cogeneration plant installation. The draft Authority To Construct (ATC) for this project was obtained two weeks after submittal of the ATC application. 30-day public notification was required due to the proximity of the facility to nearby schools. The final ATC was issued two months after the application was submitted, including the 30-day public notification period.

Gas Turbine Cogeneration – South Coast Air Quality Management District. Project manager and lead engineer for preparation of air permit application for two 5.5 MW gas turbines in cogeneration configuration for county government center. The turbines are equipped with selective catalytic reduction (SCR) and oxidation catalyst to comply with SCAQMD BACT requirements. Aqueous urea is used as the SCR reagent to avoid trigger hazardous material storage requirements. The NO_x and CO continuous emissions monitoring systems are covered by a separate permit.

Peaker Gas Turbines – Evaluation of NO_x Control Options for Installations in San Diego County.

Lead engineer for evaluation of NO_x control options available for 1970s vintage simple-cycle gas turbines proposed for peaker sites in San Diego County. Dry low-NO_x (DLN) combustors, catalytic combustors, high-temperature SCR, and NO_x absorption/conversion (SCONO_x) were evaluated for each candidate turbine make/model. High-temperature SCR was selected as the NO_x control option to meet a 5 ppm NO_x emission requirement.

Hospital Cogeneration Plant Gas Turbines – San Joaquin Valley Unified Air Pollution Control District.

Project manager and lead engineer for preparation of air permit application and Best Available Control Technology (BACT) evaluation for hospital cogeneration plant installation. The BACT included the review of DLN combustors, catalytic combustors, high-temperature SCR and SCONO_x. DLN combustion followed by high temperature SCR was selected as the NO_x control system for this installation. The high temperature SCR is located upstream of the heat recovery steam generator (HRSG) to allow the diversion of exhaust gas around the HRSG without compromising the effectiveness of the NO_x control system.

1,000 MW Coastal Combined-Cycle Power Plant – Feasibility of Dry Cooling.

Expert witness in on-going effort to require use of dry cooling on proposed 1,000 MW combined-cycle “repower” project at site of an existing 1,000 MW utility boiler plant. Project proponent argued that site was too small for properly sized air-cooled condenser (ACC) and that use of ACC would cause 12-month construction delay. Demonstrated that ACC could easily be located on the site by splitting total of up to 80 cells between two available locations at the site. Also demonstrated that an ACC optimized for low height and low noise would minimize or eliminate proponent claims of negative visual and noise impacts.

Industrial Cogeneration Plant Gas Turbines – Upgrade of Turbine Power Output.

Project manager and lead engineer for preparation of Best Available Control Technology (BACT) evaluation for proposed gas turbine upgrade. The BACT included the review of DLN combustors, catalytic combustors, high-, standard-, and low-temperature SCR, and SCONO_x. Successfully negotiated air permit that allowed facility to initially install DLN combustors and operate under a NO_x plantwide “cap.” Within two major turbine overhauls, or approximately eight years, the NO_x emissions per turbine must be at or below the equivalent of 5 ppm. The 5 ppm NO_x target will be achieved through technological in-combustor NO_x control such as catalytic combustion, or SCR or SCR equivalent end-of-pipe NO_x control technologies if catalytic combustion is not available.

Gas Turbines – Modification of RATA Procedures for Time-Share CEM.

Project manager and lead engineer for the development of alternate CO continuous emission monitor (CEM) Relative Accuracy Test Audit (RATA) procedures for time-share CEM system serving three 7.9 MW turbines located in San Diego. Close interaction with San Diego APCD and EPA Region 9 engineers was required to

receive approval for the alternate CO RATA standard. The time-share CEM then passed the annual RATA without problems as a result of changes to some CEM hardware and the more flexible CO RATA standard.

Gas Turbines – Evaluation of NO_x Control Technology Performance. Lead engineer for performance review of dry low-NO_x combustors, catalytic combustors, high-, standard-, and low-temperature selective catalytic reduction (SCR), and NO_x absorption/conversion (SCONO_x). Major turbine manufacturers and major manufacturers of end-of-pipe NO_x control systems for gas turbines were contacted to determine current cost and performance of NO_x control systems. A comparison of 1993 to 1999 “\$/kwh” and “\$/ton” cost of these control systems was developed in the evaluation.

Lead engineer for evaluation for proposed combined cycle gas turbine NO_x and CO control systems.

Project was in litigation over contract terms, and there was concern that the GE Frame 7FA turbine could not meet the 3 ppm NO_x permit limit using a conventional combustor with water injection followed by SCR. Operations personnel at GE Frame 7FA installations around the country were interviewed, along with principal SCR vendors, to corroborate that the installation could continuously meet the 3 ppm NO_x limit.

Gas Turbines – Title V "Presumptively Approvable" Compliance Assurance Monitoring Protocol.

Project manager and lead engineer for the development of a "presumptively approval" NO_x parametric emissions monitoring system (PEMS) protocol for industrial gas turbines. "Presumptively approvable" means that any gas turbine operator selecting this monitoring protocol can presume it is acceptable to the U.S. EPA. Close interaction with the gas turbine manufacturer's design engineering staff and the U.S. EPA Emissions Measurement Branch (Research Triangle Park, NC) was required to determine modifications necessary to the current PEMS to upgrade it to "presumptively approvable" status.

Environmental Due Diligence Review of Gas Turbine Sites – Mexico. Task leader to prepare regulatory compliance due diligence review of Mexican requirements for gas turbine power plants. Project involves eleven potential sites across Mexico, three of which are under construction. Scope involves identification of all environmental, energy sales, land use, and transportation corridor requirements for power projects in Mexico. Coordinator of Mexican environmental subcontractors gathering on-site information for each site, and translator of Spanish supporting documentation to English.

Development of Air Emission Standards for Gas Turbines - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian gas turbine power plants. All major gas turbine power plants in Peru are currently using water injection to increase turbine power output. Recommended that 42 ppm on natural gas and 65 ppm on diesel (corrected to 15% O₂) be established as the NO_x limit for existing gas turbine power plants. These limits reflect NO_x levels readily achievable using water injection at high load. Also recommended that new gas turbine sources be subject to a BACT review requirement.

Gas Turbines – Title V Permit Templates. Lead engineer for the development of standardized permit templates for approximately 100 gas turbines operated by the oil and gas industry in the San Joaquin Valley. Emissions limits and monitoring requirements were defined for units ranging from GE Frame 7 to Solar Saturn turbines. Stand-alone templates were developed based on turbine size and NO_x control equipment. NO_x utilized in the target turbine population ranged from water injection alone to water injection combined with SCR.

Gas Turbines – Evaluation of NO_x, SO₂ and PM Emission Profiles. Performed a comparative evaluation of the NO_x, SO₂ and particulate (PM) emission profiles of principal utility-scale gas turbines for an independent power producer evaluating project opportunities in Latin America. All gas turbine models in the 40 MW to 240 MW range manufactured by General Electric, Westinghouse, Siemens and ABB were included in the evaluation.

Stationary Internal Combustion Engine (ICE) RACT/BARCT Evaluation. Lead engineer for evaluation of retrofit NO_x control options available for the oil and gas production industry gas-fired ICE population in the San Joaquin Valley affected by proposed RACT and BARCT emission limits. Evaluation centered on lean-burn compressor engines under 500 bhp, and rich-burn constant and cyclically loaded (rod pump) engines under 200 bhp. The results of the evaluation indicated that rich burn cyclically-loaded rod pump engines comprised 50 percent of the affected ICE population, though these ICEs accounted for only 5 percent of the uncontrolled gas-fired stationary ICE NO_x emissions. Recommended retrofit NO_x control strategies included: air/fuel ratio adjustment for rod pump ICEs, Non-selective catalytic reduction (NSCR) for rich-burn, constant load ICEs, and "low emission" combustion modifications for lean burn ICEs.

Development of Air Emission Standards for Stationary ICEs - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian stationary ICE power plants. Draft 1997 World Bank NO_x and particulate emission limits for stationary ICE power plants served as the basis for proposed MEM emission limits. A detailed review of ICE emissions data provided in PAMAs submitted to the MEM was performed to determine the level of effort that would be required by Peruvian industry to meet the proposed NO_x and particulate emission limits. The draft 1997 WB emission limits were revised to reflect reasonably achievable NO_x and particulate emission limits for ICEs currently in operation in Peru.

Air Toxics Testing of Natural Gas-Fired ICEs. Project manager for test plan/test program to measure volatile and semi-volatile organic air toxics compounds from fourteen gas-fired ICEs used in a variety of oil and gas production applications. Test data was utilized by oil and gas production facility owners throughout California to develop accurate ICE air toxics emission inventories.

AIR ENGINEERING/AIR TESTING PROJECT EXPERIENCE – GENERAL

Reverse Air Fabric Filter Retrofit Evaluation – Coal-Fired Boiler. Lead engineer for upgrade of reverse air fabric filters serving coal-fired industrial boilers. Fluorescent dye injected to pinpoint broken bags and damper leaks. Corrosion of pneumatic actuators serving reverse air valves and inadequate insulation identified as principal causes of degraded performance.

Pulse-Jet Fabric Filter Performance Evaluation – Gold Mine. Lead engineer on upgrade of pulse-jet fabric filter and associated exhaust ventilation system serving an ore-crushing facility at a gold mine. Fluorescent dye used to identify bag collar leaks, and modifications were made to pulse air cycle time and duration. This marginal source was in compliance at 20 percent of emission limit following completion of repair work.

Pulse-Jet Fabric Filter Retrofit - Gypsum Calciner. Lead engineer on upgrade of pulse-jet fabric filter controlling particulate emissions from a gypsum calciner. Recommendations included a modified bag clamping mechanism, modified hopper evacuation valve assembly, and changes to pulse air cycle time and pulse duration.

Wet Scrubber Retrofit – Plating Shop. Project engineer on retrofit evaluation of plating shop packed-bed wet scrubbers failing to meet performance guarantees during acceptance trials, due to excessive mist carryover. Recommendations included relocation of the mist eliminator (ME), substitution of the original chevron blade ME with a mesh pad ME, and use of higher density packing material to improve exhaust gas distribution. Wet scrubbers passed acceptance trials following completion of recommended modifications.

Electrostatic Precipitator (ESP) Retrofit Evaluation – MSW Boiler. Lead engineer for retrofit evaluation of single field ESP on a municipal solid waste (MSW) boiler. Recommendations included addition of automated power controller, inlet duct turning vanes, and improved collecting plate rapping system.

ESP Electric Coil Rapper Vibration Analysis Testing - Coal-Fired Boiler. Lead engineer for evaluation of ESP rapper effectiveness test program on three field ESP equipped with "magnetically induced gravity return" (MIGR) rappers. Accelerometers were placed in a grid pattern on ESP collecting plates to determine maximum

instantaneous plate acceleration at a variety of rafter power setpoints. Testing showed that the rappers met performance specification requirements.

Aluminum Remelt Furnace Particulate Emissions Testing. Project manager and lead engineer for high temperature (1,600 °F) particulate sampling of a natural gas-fired remelt furnace at a major aluminum rolling mill. Objectives of test program were to: 1) determine if condensable particulate was present in stack gases, and 2) to validate the accuracy of the in-stack continuous opacity monitor (COM). Designed and constructed a customized high temperature (inconel) PM₁₀/Mtd 17 sampling assembly for test program. An onsite natural gas-fired boiler was also tested to provide comparative data for the condensable particulate portion of the test program. Test results showed that no significant levels of condensable particulate in the remelt furnace exhaust gas, and indicated that the remelt furnace and boiler had similar particulate emission rates. Test results also showed that the COM was accurate.

Aluminum Remelt Furnace CO and NO_x Testing. Project manager and lead engineer for continuous week-long testing of CO and NO_x emissions from aluminum remelt furnace. Objective of test program was to characterize CO and NO_x emissions from representative remelt furnace for use in the facility's criteria pollution emissions inventory. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide ± 1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system.

PETROLEUM REFINERY AIR ENGINEERING/TESTING EXPERIENCE

Big West Refinery Expansion EIS. Lead engineer on comparative cost analysis of proposed wet cooling tower and fin-fan air cooler for process cooling water for the proposed clean fuels expansion project at the Big West Refinery in Bakersfield, California. Selection of the fin-fan air-cooler would eliminate all consumptive water use and wastewater disposal associated with the cooling tower. Air emissions of VOC and PM₁₀ would be reduced with the fin-fan air-cooler even though power demand of the air-cooler is incrementally higher than that of the cooling tower. Fin-fan air-coolers with approach temperatures of 10 °F and 20 °F were evaluated. The annualized cost of the fin-fan air-cooler with a 20 °F approach temperature is essentially the same as that of the cooling tower when the cost of all ancillary cooling tower systems are considered.

Criteria and Air Toxic Pollutant Emissions Inventory for Proposed Refinery Modifications. Project manager and technical lead for development of baseline and future refinery air emissions inventories for process modifications required to produce oxygenated gasoline and desulfurized diesel fuel at a California refinery. State of the art criteria and air toxic pollutant emissions inventories for refinery point, fugitive and mobile sources were developed. Point source emissions estimates were generated using onsite criteria pollutant test data, onsite air toxics test data, and the latest air toxics emission factors from the statewide refinery air toxics inventory database. The fugitive volatile organic compound (VOC) emissions inventories were developed using the refinery's most recent inspection and maintenance (I&M) monitoring program test data to develop site-specific component VOC emission rates. These VOC emission rates were combined with speciated air toxics test results for the principal refinery process streams to produce fugitive VOC air toxics emission rates. The environmental impact report (EIR) that utilized this emission inventory data was the first refinery "Clean Fuels" EIR approved in California.

Development of Air Emission Standards for Petroleum Refinery Equipment - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian petroleum refineries. The sources included in the scope of this project included: 1) SO₂ and NO_x refinery heaters and boilers, 2) desulfurization of crude oil, particulate and SO₂ controls for fluid catalytic cracking units (FCCU), 3) VOC and CO emissions from flares, 4) vapor recovery systems for marine unloading, truck loading, and crude oil/refined products storage tanks, and 5) VOC emissions from process fugitive sources such as pressure relief valves, pumps, compressors and flanges. Proposed emission limits were developed for new and existing refineries based on a thorough evaluation of the available air emission control technologies for the affected refinery sources. Leading vendors of refinery control technology, such as John Zink and Exxon Research, provided estimates of retrofit costs for the largest Peruvian refinery, La Pampilla,

located in Lima. Meetings were held in Lima with refinery operators and MEM staff to discuss the proposed emission limits and incorporate mutually agreed upon revisions to the proposed limits for existing Peruvian refineries.

Air Toxic Pollutant Emissions Inventory for Existing Refinery. Project manager and technical lead for air toxic pollutant emissions inventory at major California refinery. Emission factors were developed for refinery heaters, boilers, flares, sulfur recovery units, coker deheading, IC engines, storage tanks, process fugitives, and catalyst regeneration units. Onsite source test results were utilized to characterize emissions from refinery combustion devices. Where representative source test results were not available, AP-42 VOC emission factors were combined with available VOC air toxics speciation profiles to estimate VOC air toxic emission rates. A risk assessment based on this emissions inventory indicated a relatively low health risk associated with refinery operations. Benzene, 1,3-butadiene and PAHs were the principal health risk related pollutants emitted.

Air Toxics Testing of Refinery Combustion Sources. Project manager for comprehensive air toxics testing program at a major California refinery. Metals, Cr⁺⁶, PAHs, H₂S and speciated VOC emissions were measured from refinery combustion sources. High temperature Cr⁺⁶ stack testing using the EPA Cr⁺⁶ test method was performed for the first time in California during this test program. Representatives from the California Air Resources Board source test team performed simultaneous testing using ARB Method 425 (Cr⁺⁶) to compare the results of EPA and ARB Cr⁺⁶ test methodologies. The ARB approved the test results generated using the high temperature EPA Cr⁺⁶ test method.

Air Toxics Testing of Refinery Fugitive Sources. Project manager for test program to characterize air toxic fugitive VOC emissions from fifteen distinct process units at major California refinery. Gas, light liquid, and heavy liquid process streams were sampled. BTXE, 1,3-butadiene and propylene concentrations were quantified in gas samples, while BTXE, cresol and phenol concentrations were measured in liquid samples. Test results were combined with AP-42 fugitive VOC emission factors for valves, fittings, compressors, pumps and PRVs to calculate fugitive air toxics VOC emission rates.

OIL AND GAS PRODUCTION AIR ENGINEERING/TESTING EXPERIENCE

Air Toxics Testing of Oil and Gas Production Sources. Project manager and lead engineer for test plan/test program to determine VOC removal efficiency of packed tower scrubber controlling sulfur dioxide emissions from a crude oil-fired steam generator. Ratfish 55 VOC analyzers were used to measure the packed tower scrubber VOC removal efficiency. Tedlar bag samples were collected simultaneously to correlate BTX removal efficiency to VOC removal efficiency. This test was one of hundreds of air toxics tests performed during this test program for oil and gas production facilities from 1990 to 1992. The majority of the volatile air toxics analyses were performed at in-house laboratory. Project staff developed thorough familiarity with the applications and limitations of GC/MS, GC/PID, GC/FID, GC/ECD and GC/FPD. Tedlar bags, canisters, sorbent tubes and impingers were used during sampling, along with isokinetic tests methods for multiple metals and PAHs.

Air Toxics Testing of Glycol Reboiler – Gas Processing Plant. Project manager for test program to determine emissions of BTXE from glycol reboiler vent at gas processing facility handling 12 MM/cfd of produced gas. Developed innovative test methods to accurately quantify BTXE emissions in reboiler vent gas.

Air Toxics Emissions Inventory Plan. Lead engineer for the development of generic air toxics emission estimating techniques (EETs) for oil and gas production equipment. This project was performed for the Western States Petroleum Association in response to the requirements of the California Air Toxics "Hot Spots" Act. EETs were developed for all point and fugitive oil and gas production sources of air toxics, and the specific air toxics associated with each source were identified. A pooled source emission test methodology was also developed to moderate the cost of source testing required by the Act.

Fugitive NMHC Emissions from TEOR Production Field. Project manager for the quantification of fugitive Nonmethane hydrocarbon (NMHC) emissions from a thermally enhanced oil recovery (TEOR) oil production field in Kern County, CA. This program included direct measurement of NMHC concentrations in storage tank

vapor headspace and the modification of available NMHC emission factors for NMHC-emitting devices in TEOR produced gas service, such as wellheads, vapor trunklines, heat exchangers, and compressors. Modification of the existing NMHC emission factors was necessary due to the high concentration of CO₂ and water vapor in TEOR produced gases.

Fugitive Air Emissions Testing of Oil and Gas Production Fields. Project manager for test plan/test program to determine VOC and air toxics emissions from oil storage tanks, wastewater storage tanks and produced gas lines. Test results were utilized to develop comprehensive air toxics emissions inventories for oil and gas production companies participating in the test program.

Oil and Gas Production Field – Air Emissions Inventory and Air Modeling. Project manager for oil and gas production field risk assessment. Project included review and revision of the existing air toxics emission inventory, air dispersion modeling, and calculation of the acute health risk, chronic non-carcinogenic risk and carcinogenic risk of facility operations. Results indicated that fugitive H₂S emissions from facility operations posed a potential health risk at the facility fenceline.

TITLE V PERMIT APPLICATION/MONITORING PLAN EXPERIENCE

Title V Permit Application – San Diego County Industrial Facility. Project engineer tasked with preparing streamlined Title V operating permit for U.S. Navy facilities in San Diego. Principal emission units included chrome plating, lead furnaces, IC engines, solvent usage, aerospace coating and marine coating operations. For each device category in use at the facility, federal MACT requirements were integrated with District requirements in user friendly tables that summarized permit conditions and compliance status.

Title V Permit Application Device Templates - Oil and Gas Production Industry. Project manager and lead engineer to prepare Title V permit application “templates” for the Western States Petroleum Association (WSPA). The template approach was chosen by WSPA to minimize the administrative burden associated with listing permit conditions for a large number of similar devices located at the same oil and gas production facility. Templates are being developed for device types common to oil and gas production operations. Device types include: boilers, steam generators, process heaters, gas turbines, IC engines, fixed-roof storage tanks, fugitive components, flares, and cooling towers. These templates will serve as the core of Title V permit applications prepared for oil and gas production operations in California.

Title V Permit Application - Aluminum Rolling Mill. Project manager and lead engineer for Title V permit application prepared for largest aluminum rolling mill in the western U.S. Responsible for the overall direction of the permit application project, development of a monitoring plan for significant emission units, and development of a hazardous air pollutant (HAP) emissions inventory. The project involved extensive onsite data gathering, frequent interaction with the plant's technical and operating staff, and coordination with legal counsel and subcontractors. The permit application was completed on time and in budget.

Title V Model Permit - Oil and Gas Production Industry. Project manager and lead engineer for the comparative analysis of regional and federal requirements affecting oil and gas production industry sources located in the San Joaquin Valley. Sources included gas turbines, IC engines, steam generators, storage tanks, and process fugitives. From this analysis, a model applicable requirements table was developed for a sample device type (storage tanks) that covered the entire population of storage tanks operated by the industry. The U.S. EPA has tentatively approved this model permit approach, and work is ongoing to develop comprehensive applicable requirements tables for each major category of sources operated by the oil and gas industry in the San Joaquin Valley.

Title V Enhanced Monitoring Evaluation of Oil and Gas Production Sources. Lead engineer to identify differences in proposed EPA Title V enhanced monitoring protocols and the current monitoring requirements for oil and gas production sources in the San Joaquin Valley. The device types evaluated included: steam generators, stationary ICEs, gas turbines, fugitives, fixed roof storage tanks, and thermally enhanced oil recovery (TEOR) well vents. Principal areas of difference included: more stringent Title V O&M requirements

for parameter monitors (such as temperature, fuel flow, and O₂), and more extensive Title V recordkeeping requirements.

RACT/BARCT/BACT EVALUATIONS

RACT/BARCT Reverse Jet Scrubber/Fiberbed Mist Eliminator Retrofit Evaluation. Project manager and lead engineer on project to address the inability of existing wet electrostatic precipitators (ESPs) and atomized mist scrubbers to adequately remove low concentration submicron particulate from high volume recovery boiler exhaust gas at the Alaska Pulp Corporation mill in Sitka, AK. The project involved thorough on-site inspections of existing control equipment, detailed review of maintenance and performance records, and a detailed evaluation of potential replacement technologies. These technologies included a wide variety of scrubbing technologies where manufacturers claimed high removal efficiencies on submicron particulate in high humidity exhaust gas. Packed tower scrubbers, venturi scrubbers, reverse jet scrubbers, fiberbed mist eliminators and wet ESPs were evaluated. Final recommendations included replacement of atomized mist scrubber with reverse jet scrubber and upgrading of the existing wet ESPs. The paper describing this project was published in the May 1992 TAPPI Journal.

Aluminum Smelter RACT Evaluation - Prebake. Project manager and technical lead for CO and PM₁₀ RACT evaluation for prebake facility. Retrofit control options for CO emissions from the anode bake furnace, potline dry scrubbers and the potroom roof vents were evaluated. PM₁₀ emissions from the coke kiln, potline dry scrubbers, potroom roof vents, and miscellaneous potroom fugitive sources were addressed. Four CO control technologies were identified as technologically feasible for potline CO emissions: potline current efficiency improvement through the addition of underhung busswork and automated puncher/feeders, catalytic incineration, recuperative incineration and regenerative incineration. Current efficiency improvement was identified as probable CO RACT if onsite test program demonstrated the effectiveness of this approach. Five PM₁₀ control technologies were identified as technologically feasible: increased potline hooding efficiency through redesign of shields, the addition of a dense-phase conveying system, increased potline air evacuation rate, wet scrubbing of roof vent emissions, and fabric filter control of roof vent emissions.

RACT/BACT Testing/Evaluation of PM₁₀ Mist Eliminators on Five-Stand Cold Mill. Project manager and lead engineer for fiberbed mist eliminator and mesh pad mist eliminator comparative pilot test program on mixed phase aerosol (PM₁₀)/gaseous hydrocarbon emissions from aluminum high speed cold rolling mill. Utilized modified EPA Method 5 sampling train with portion of sample gas diverted (after particulate filter) to Ratfisch 55 VOC analyzer. This was done to permit simultaneous quantification of aerosol and gaseous hydrocarbon emissions in the exhaust gas. The mesh pad mist eliminator demonstrated good control of PM₁₀ emissions, though test results indicated that the majority of captured PM₁₀ evaporated in the mesh pad and was emitted as VOC.

Aluminum Remelt Furnace/Rolling Mill RACT Evaluations. Lead engineer for comprehensive CO and PM₁₀ RACT evaluation for the largest aluminum sheet and plate rolling mill in western U.S. Significant sources of CO emissions from the facility included the remelt furnaces and the coater line. The potential CO RACT options for the remelt furnaces included: enhanced maintenance practices, preheating combustion air, installation of fully automated combustion controls, and energy efficiency modifications.

BARCT Low NO_x Burner Conversion – Industrial Boilers. Lead engineer for evaluation of low NO_x burner options for natural gas-fired industrial boilers. Also evaluated methanol and propane as stand-by fuels to replace existing diesel stand-by fuel system. Evaluated replacement of steam boilers with gas turbine co-generation system.

BACT Packed Tower Scrubber/Mist Eliminator Performance Evaluations. Project manager and lead engineer for Navy-wide plating shop air pollution control technology evaluation and emissions testing program. Mist eliminators and packed tower scrubbers controlling metal plating processes, which included hard chrome, nickel, copper, cadmium and precious metals plating, were extensively tested at three Navy plating shops.

Chemical cleaning and stripping tanks, including hydrochloric acid, sulfuric acid, chromic acid and caustic, were also tested. The final product of this program was a military design specification for plating and chemical cleaning shop air pollution control systems. The hydrochloric acid mist sampling procedure developed during this program received a protected patent.

BACT Packed Tower Scrubber/UV Oxidation System Pilot Test Program. Technical advisor for pilot test program of packed tower scrubber/ultraviolet (UV) light VOC oxidation system controlling VOC emissions from microchip manufacturing facility in Los Angeles. The testing was sponsored in part by the SCAQMD's Innovative Technology Demonstration Program, to demonstrate this innovative control technology as BACT for microchip manufacturing operations. The target compounds were acetone, methylethylketone (MEK) and 1,1,1-trichloroethane, and compound concentrations ranged from 10-100 ppmv. The single stage packed tower scrubber consistently achieved greater than 90% removal efficiency on the target compounds. The residence time required in the UV oxidation system for effective oxidation of the target compounds proved significantly longer than the residence time predicted by the manufacturer.

BACT Pilot Testing of Venturi Scrubber on Gas/Aerosol VOC Emission Source. Technical advisor for project to evaluate venturi scrubber as BACT for mixed phase aerosol/gaseous hydrocarbon emissions from deep fat fryer. Venturi scrubber demonstrated high removal efficiency on aerosol, low efficiency on VOC emissions. A number of VOC tests indicated negative removal efficiency. This anomaly was traced to a high hydrocarbon concentration in the scrubber water. The pilot unit had been shipped directly to the jobsite from another test location by the manufacturer without any cleaning or inspection of the pilot unit.

Pulp Mill Recovery Boiler BACT Evaluation. Lead engineer for BACT analysis for control of SO₂, NO_x, CO, TNMHC, TRS and particulate emissions from the proposed addition of a new recovery furnace at a kraft pulp mill in Washington. A "top down" approach was used to evaluate potential control technologies for each of the pollutants considered in the evaluation.

Air Pollution Control Equipment Design Specification Development. Lead engineer for the development of detailed Navy design specifications for wet scrubbers and mist eliminators. Design specifications were based on field performance evaluations conducted at the Long Beach Naval Shipyard, Norfolk Naval Shipyard, and Jacksonville Naval Air Station. This work was performed for the U.S. Navy to provide generic design specifications to assist naval facility engineering divisions with air pollution control equipment selection. Also served as project engineer for the development of Navy design specifications for ESPs and fabric filters.

CONTINUOUS EMISSION MONITOR (CEM) PROJECT EXPERIENCE

Process Heater CO and NO_x CEM Relative Accuracy Testing. Project manager and lead engineer for process heater CO and NO_x analyzer relative accuracy test program at petrochemical manufacturing facility. Objective of test program was to demonstrate that performance of onsite CO and NO_x CEMs was in compliance with U.S. EPA "Boiler and Industrial Furnace" hazardous waste co-firing regulations. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide ± 1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system. One of the two process heater CEM systems tested failed the initial test due to leaks in the gas conditioning system. Troubleshooting was performed using O₂ analyzers, and the leaking component was identified and replaced. This CEM system met all CEM relative accuracy requirements during the subsequent retest.

Performance Audit of NO_x and SO₂ CEMs at Coal-Fired Power Plant. Lead engineer on system audit and challenge gas performance audit of NO_x and SO₂ CEMs at a coal-fired power plant in southern Nevada. Dynamic and instrument calibration checks were performed on the CEMs. A detailed visual inspection of the CEM system, from the gas sampling probes at the stack to the CEM sample gas outlet tubing in the CEM trailer, was also conducted. The CEMs passed the dynamic and instrument calibration requirements specified in EPA's Performance Specification Test - 2 (NO_x and SO₂) alternative relative accuracy requirements.

LATIN AMERICA ENVIRONMENTAL PROJECT EXPERIENCE

Assessment of operational deficiencies of Camisa pipeline – Peru. Project leader of multi-year assessment of root causes of ruptures on Camisea 14-inch natural gas liquids pipeline for non-profit client. Determined that primary causes of hurried construction in difficult and unstable terrain, unstable right-of-way in the jungle sector due to inadequate erosion control practices, and inadequate pipe wall thickness to withstand external lateral forces. Two assessments were developed during the course of the project documenting deficiencies and recommending remedial actions.

Evaluation of U.S.-Mexico Border Region Copper Smelter Compliance with Treaty Obligations – Mexico. Project manager and lead engineer to evaluate compliance of U.S. and Mexican border region copper smelters with the SO₂ monitoring, recordkeeping and reporting requirements in Annex IV [Copper Smelters] of the La Paz Environmental Treaty. Identified potential problems with current ambient and stack monitoring practices that could result in underestimating the impact of SO₂ emissions from some of these copper smelters. Identified additional source types, including hazardous waste incinerators and power plants, that should be considered for inclusion in the La Paz Treaty process.

Development of Air Emission Limits for ICE Cogeneration Plant - Panamá. Lead engineer assisting U.S. cogeneration plant developer to permit an ICE cogeneration plant at a hotel/casino complex in Panama. Recommended the use of modified draft World Bank NO_x and PM limits for ICE power plants. The modification consisted of adding a thermal efficiency factor adjustment to the draft World Bank NO_x and PM limits. These proposed ICE emission limits are currently being reviewed by Panamanian environmental authorities.

Mercury Emissions Inventory for Stationary Sources in Northern Mexico. Project manager and lead engineer to estimate mercury emissions from stationary sources in Northern Mexico. Major potential sources of mercury emissions include solid- and liquid-fueled power plants, cement kilns co-firing hazardous waste, and non-ferrous metal smelters. Emission estimates were provided for approximately eighty of these sources located in Northern Mexico. Coordinated efforts of two Mexican subcontractors, located in Mexico City and Hermosillo, to obtain process throughput data for each source included in the inventory.

Translation of U.S. EPA Scrap Tire Combustion Emissions Estimation Document – Mexico. Evaluated the Translated a U.S. EPA scrap tire combustion emissions estimation document from English to Spanish for use by Latin American environmental professionals.

Environmental Audit of Aluminum Production Facilities – Venezuela. Evaluated the capabilities of existing air, wastewater and solid/hazardous waste control systems used by the aluminum industry in eastern Venezuela. This industry will be privatized in the near future. Estimated the cost to bring these control systems into compliance with air, wastewater and solid/hazardous waste standards recently promulgated in Venezuela. Also served as technical translator for team of U.S. environmental engineers involved in the due diligence assessment.

Assessment of Environmental Improvement Projects – Chile and Peru. Evaluated potential air, water, soil remediation and waste recycling projects in Lima, Peru and Santiago, Chile for feasibility study funding by the U.S. Trade and Development Agency. Project required onsite interaction with in-country decisionmakers (in Spanish). Projects recommended for feasibility study funding included: 1) an air quality technical support project for the Santiago, Chile region, and 2) soil remediation/metals recovery projects at two copper mine/smelter sites in Peru.

Air Pollution Control Training Course – Mexico. Conducted two-day Spanish language air quality training course for environmental managers of assembly plants in Mexicali, Mexico. Spanish-language course manual prepared by Powers Engineering. Practical laboratory included training in use of combustion gas analyzer, flame ionization detector (FID), photoionization detector (PID), and occupational sampling.

Stationary Source Emissions Inventory – Mexico. Developed a comprehensive air emissions inventory for stationary sources in Nogales, Sonora. This project requires frequent interaction with Mexican state and federal environmental authorities. The principal Powers Engineering subcontractor on this project is a Mexican firm located in Hermosillo, Sonora.

VOC Measurement Program – Mexico. Performed a comprehensive volatile organic compound (VOC) measurements program at a health products fabrication plant in Mexicali, Mexico. An FID and PID were used to quantify VOCs from five processes at the facility. Occupational exposures were also measured. Worker exposure levels were above allowable levels at several points in the main assembly area.

Fluent in Spanish. Studied at the Universidad de Michoacán in Morelia, Mexico, 1993, and at the Colegio de España in Salamanca, Spain, 1987-88. Have lectured (in Spanish) on air monitoring and control equipment at the Instituto Tecnológico de Tijuana. Maintain contact with Comisión Federal de Electricidad engineers responsible for operation of wind and geothermal power plants in Mexico, and am comfortable operating in the Mexican business environment.

PUBLICATIONS

Bill Powers, “*More Distributed Solar Means Fewer New Combustion Turbines,*” Natural Gas & Electricity Journal, Vol. 29, Number 2, September 2012, pp. 17-20.

Bill Powers, “*Federal Government Betting on Wrong Solar Horse,*” Natural Gas & Electricity Journal, Vol. 27, Number 5, December 2010,

Bill Powers, “*Today’s California Renewable Energy Strategy—Maximize Complexity and Expense,*” Natural Gas & Electricity Journal, Vol. 27, Number 2, September 2010, pp. 19-26.

Bill Powers, “*Environmental Problem Solving Itself Rapidly Through Lower Gas Costs,*” Natural Gas & Electricity Journal, Vol. 26, Number 4, November 2009, pp. 9-14.

Bill Powers, “*PV Pulling Ahead, but Why Pay Transmission Costs?*” Natural Gas & Electricity Journal, Vol. 26, Number 3, October 2009, pp. 19-22.

Bill Powers, “*Unused Turbines, Ample Gas Supply, and PV to Solve RPS Issues,*” Natural Gas & Electricity Journal, Vol. 26, Number 2, September 2009, pp. 1-7.

Bill Powers, “*CEC Cancels Gas-Fed Peaker, Suggesting Rooftop Photovoltaic Equally Cost-Effective,*” Natural Gas & Electricity Journal, Vol. 26, Number 1, August 2009, pp. 8-13.

Bill Powers, “*San Diego Smart Energy 2020 – The 21st Century Alternative,*” San Diego, October 2007.

Bill Powers, “*Energy, the Environment, and the California – Baja California Border Region,*” Electricity Journal, Vol. 18, Issue 6, July 2005, pp. 77-84.

W.E. Powers, “*Peak and Annual Average Energy Efficiency Penalty of Optimized Air-Cooled Condenser on 515 MW Fossil Fuel-Fired Utility Boiler,*” presented at California Energy Commission/Electric Power Research Institute Advanced Cooling Technologies Symposium, Sacramento, California, June 2005.

W.E. Powers, R. Wydrum, P. Morris, “*Design and Performance of Optimized Air-Cooled Condenser at Crockett Cogeneration Plant,*” presented at EPA Symposium on Technologies for Protecting Aquatic Organisms from Cooling Water Intake Structures, Washington, DC, May 2003.

P. Pai, D. Niemi, W.E. Powers, “*A North American Anthropogenic Inventory of Mercury Emissions,*” presented at Air & Waste Management Association Annual Conference in Salt Lake City, UT, June 2000.

P.J. Blau and W.E. Powers, *"Control of Hazardous Air Emissions from Secondary Aluminum Casting Furnace Operations Through a Combination of: Upstream Pollution Prevention Measures, Process Modifications and End-of-Pipe Controls,"* presented at 1997 AWMA/EPA Emerging Solutions to VOC & Air Toxics Control Conference, San Diego, CA, February 1997.

W.E. Powers, et. al., *"Hazardous Air Pollutant Emission Inventory for Stationary Sources in Nogales, Sonora, Mexico ,"* presented at 1995 AWMA/EPA Emissions Inventory Specialty Conference, RTP, NC, October 1995.

W.E. Powers, *"Develop of a Parametric Emissions Monitoring System to Predict NO_x Emissions from Industrial Gas Turbines,"* presented at 1995 AWMA Golden West Chapter Air Pollution Control Specialty Conference, Ventura, California, March 1995.

W. E. Powers, et. al., *"Retrofit Control Options for Particulate Emissions from Magnesium Sulfite Recovery Boilers,"* presented at 1992 TAPPI Envr. Conference, April 1992. Published in *TAPPI Journal*, July 1992.

S. S. Parmar, M. Short, W. E. Powers, *"Determination of Total Gaseous Hydrocarbon Emissions from an Aluminum Rolling Mill Using Methods 25, 25A, and an Oxidation Technique,"* presented at U.S. EPA Measurement of Toxic and Related Air Pollutants Conference, May 1992.

N. Meeks, W. E. Powers, *"Air Toxics Emissions from Gas-Fired Internal Combustion Engines,"* presented at AIChE Summer Meeting, August 1990.

W. E. Powers, *"Air Pollution Control of Plating Shop Processes,"* presented at 7th AES/EPA Conference on Pollution Control in the Electroplating Industry, January 1986. Published in *Plating and Surface Finishing* magazine, July 1986.

H. M. Davenport, W. E. Powers, *"Affect of Low Cost Modifications on the Performance of an Undersized Electrostatic Precipitator,"* presented at 79th Air Pollution Control Association Conference, June 1986.

AWARDS

Engineer of the Year, 1991 – ENSR Consulting and Engineering, Camarillo

Engineer of the Year, 1986 – Naval Energy and Environmental Support Activity, Port Hueneme

Productivity Excellence Award, 1985 – U. S. Department of Defense

PATENTS

Sedimentation Chamber for Sizing Acid Mist, Navy Case Number 70094

Attachment B

List of reviewed materials

1. U.S. Energy Information Administration, Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860) (Apr. 2025), <https://www.eia.gov/electricity/data/eia860m/>.
2. U.S. EIA, Form EIA-923 detailed data with previous form data (EIA-906/920) (Apr. 2025), <https://www.eia.gov/electricity/data/eia923/>.
3. U.S. EIA, csv dataset, “MISO_load-temp_hr_2023” (accessed June 13, 2025).
4. Michigan PSC Case No. U-21090, Revised Direct Testimony and Exhibits of Norman J. Kapala on Behalf of Consumers Energy Company (Dec. 2021)
5. Michigan PSC Case No. U-21389, Direct Testimony and Exhibits of Richard T. Blumenstock on Behalf of Consumers Energy Company (May 2023)
6. Michigan PSC, Case No. U-21258, Direct Testimony and Exhibits of Nathan J. Hoffman on Behalf of Consumers Energy Company (Mar. 2024).
7. Michigan PSC Case No. U-21585, Direct Testimony and Exhibits of Richard T. Blumenstock on Behalf of Consumers Energy Company (May 2024)
8. Michigan PSC, Case No. U-21424, Direct Testimony and Exhibits of Nathan J. Hoffman on Behalf of Consumers Energy Company (Mar. 2025).
9. Michigan PSC Case No. U-21870, Direct Testimony and Exhibits of Richard T. Blumenstock on Behalf of Consumers Energy Company (June 2025)
10. M. Hafner, G. Luciani, *The Palgrave Handbook of International Energy Economics* (2022).
11. International Energy Agency, *The Role of CCUS in Low-Carbon Power Systems* (2021).
12. NERC, 2024 State of Reliability (June 2024).
13. International Energy Agency, *Increasing The Flexibility of Coal-Fired Power Plants* (Sept. 2014).
14. NERC, *Energy Storage: Overview of Electrochemical Storage* (Feb. 2021), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Master_ESAT_Report.pdf.
15. General Electric, *Get to know the LM6000* (2025) <https://www.gevernova.com/gas-power/products/gas-turbines/lm6000>.

16. National Association of Regulatory Utility Commissioners (“NARUC”), *Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices* (Jan. 2020).
17. Energy Innovation, *Coal Power 28 Percent More Expensive in 2024 Than in 2021* (June 5, 2025)
18. Campbell National Pollutant Discharge Elimination System Permit No. MI000142 (Oct. 2021)
19. Campbell Renewable Operating Permit No. MI-ROP-B2835-2020b and Permit to Install (MI-PTI-B2835-2020b)
20. Air permitting documents uploaded to the Michigan Department of Environment, Great Lakes, and Energy (“EGLE”) webpage for Campbell between May 28, 2025 and June 6, 2025 (available at <https://mienviro.michigan.gov/nsite/map/results/detail/-977712189711639421/documents>)
 - a. PM and HCI 40 CFR 63 Subpart UUUUU Test Protocol EUBOILER1 (uploaded May 28, 2025)
 - b. Air Quality Test Observation Report (uploaded May 29, 2025)
 - c. Air Quality Test Observation Form (uploaded June 3, 2025)
 - d. Hg CEMS Relative Accuracy Test Audit Test Protocol EUBOILER1 (uploaded June 5, 2025)
 - e. CEMS Relative Accuracy Test Protocol EUBOILER1 (uploaded June 6, 2025)
 - f. Two letters approving Protocol for Emissions Testing (both uploaded June 6, 2025)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Midcontinent)
Independent System Operator)
(MISO))

Order No. 202-26-16

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 4

DOE Campbell
Memorandum



CUI//PRIVILEGE

Department of Energy

Washington, DC 20585

May 23, 2025

MEMORANDUM FOR THE SECRETARY

FROM: ALEX FITZSIMMONS
DIRECTOR
OFFICE OF CYBERSECURITY, ENERGY SECURITY, AND
EMERGENCY RESPONSE (CESER)

SUBJECT: **ACTION:** Decision on an Order, Pursuant to Section 202(c) of the
Federal Power Act for J.H. Campbell Power Plant

ISSUE: Heading into the summer months, the Midcontinent Independent System Operator (MISO) faces potential tight reserve margins, particularly during periods of high demand or low generation resource output. Upcoming planned generation retirements contribute to these tight reserve margins, including the planned retirement of the 1,560 MW J.H. Campbell (“Campbell”) coal-fired power plant in West Olive, Michigan. As such, staff of the U.S. Department of Energy (DOE) have prepared an emergency order, pursuant to section 202(c) of the Federal Power Act (FPA), to help address potential generation shortfalls in the summer months.

The order directs MISO, in coordination with Consumers Energy (“Consumers”), to take all measures necessary to ensure that the Campbell Plant is available to operate and to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Although the Campbell Plant is owned and operated by Consumers, MISO is the balancing authority for the region and is responsible for dispatching generation. The order can be issued for up to 90 days and can subsequently be renewed in additional 90-day increments to address the ongoing emergency. Under the FPA, the DOE is required to consult with the Environmental Protection Agency (EPA) on all renewals.

BACKGROUND ON AUTHORITY UNDER SECTION 202(c): Section 202(c) of the FPA¹ allows the Secretary of Energy to order temporary interconnections of facilities or the production and delivery of electricity to resolve emergencies, and actions necessary to comply with these orders will not be found to violate Federal, state, or local environmental laws or regulations. Section 202(c) applies to any entity that owns or operates electric power generation, transmission, or distribution facilities. 202(c) orders typically order either temporary transmission interconnections or allow specific generators to operate beyond the limits that would otherwise be allowed under environmental regulations.

¹ Section 202(c) can be found at 16 U.S.C. § 824a(c), which is available here:
<https://www.law.cornell.edu/uscode/text/16/824a>

BACKGROUND ON ENERGY EMERGENCY: The North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025.² In its assessment, NERC notes that “Demand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output.” In particular, the retirement of generation capacity creates the potential for electricity supply shortfalls. NERC anticipates that the period of highest capacity shortfall for MISO will occur in August.

Multiple generation facilities located in Michigan have retired in recent years. MISO’s Planning Resource Auction Results for Planning Year 2025-26, released in April 2025, note that for the northern and central zones, which includes Michigan, “new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources” and that the results “demonstrated sufficient capacity at the regional, subregional and zonal levels, with the summer price reflecting the highest risk and a tighter supply-demand balance.”³

The results reinforce the need to increase capacity during the 2025 summer peak to address the emergency that exists. In addition, demand is expected to grow with new large load additions. According to the Energy Information Administration (EIA), “[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired [in Michigan] and no new coal-fired facilities are planned.”⁴ Additionally, “[t]ypically Michigan’s nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned. The state’s Big Rock Point nuclear power plant shut down in 1997 and the Palisades nuclear power plant closed in 2022.”⁵ Indeed, the Palisades nuclear power plant is now scheduled to restart in Fall 2025, underscoring the importance of thermal generation to the Michigan region and the need to reevaluate planned closures to address increasing demand. Palisades will not be available during the peak demand period this summer.

SENSITIVITIES: Consumers announced in 2021 that it planned to “speed closure” of Campbell in 2025, which is several years before the end of its scheduled design life.⁶ Since then, MISO and Consumers have incorporated the planned retirement into their supply forecasts and taken action to mitigate the impact of the plant’s shutdown. This includes Consumers’ recent purchase of a 1,200 MW natural gas power plant in Covert, Michigan, although the NERC Assessment still anticipates tight reserve margins.

Past the planned retirement date of May 31, Consumers has ended its contracts for coal procurement, coal delivery, and power plant staffing and may face challenges with addressing these issues on short notice. The order provides reasonable last-minute contract extensions for fuel and operations, if feasible.

² https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf

³ <https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250428694160.pdf>

⁴ <https://www.eia.gov/state/print.php?sid=MI>

⁵ <https://www.eia.gov/state/print.php?sid=MI>

⁶ <https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation>

POLICY IMPACT: None.

URGENCY: To address the ongoing energy emergency and minimize the continued risk of power outages, the order needs to be issued as soon as possible. The plant is slated to close on May 31, 2025.

RECOMMENDATION:

- **Concurrence on 202(c) Order for the J.H. Campbell Power Plant:**
 - o Recommendation: That you approve the order pursuant to section 202(c) of the Federal Power Act related to the generation system.

APPROVE: Caw DISAPPROVE: _____ NEEDS DISCUSSION: _____ DATE: 5/23/25

Attachments:

1. 202(c) order for the J.H. Campbell Power Plant

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Midcontinent)
Independent System Operator)
(MISO))
_____)

Order No. 202-26-16

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 5

DOE Order No. 202-22-4



Department of Energy
Washington, DC 20585

Order No. 202-22-4

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated by email correspondence (Dec. 23, 2022), and for the reasons set forth below, I hereby determine that an emergency exists in the electricity grid operated by PJM Interconnection, LLC (PJM) due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

On December 24, 2022, PJM, the Regional Transmission Operator (RTO) for 65 million people in thirteen states and the District of Columbia (the PJM Region), filed a *Request for Emergency Order Under Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) “to preserve the reliability of the bulk electric power system.”

The PJM Region, like many regions across the country, is currently being affected by a severe winter weather system. PJM states that this weather system caused a significant drop in temperatures across the PJM Region on December 23, 2022, accompanied by high winds in excess of 40 mph. As a consequence of the impact of wind and decreasing temperatures, the demand for electricity in the PJM Region rose to an unusually high peak load on the evening of December 23, 2022, in excess of 135,000 MW. This severely cold weather is expected to last through Sunday morning.

While the vast majority of generating units in the PJM Region continue to function adequately under these stressed conditions, some units have experienced operating difficulties due to cold weather or fuel limitations, primarily gas. Specifically, approximately 45,000 MW of generating units (the majority of which are thermal) are currently outaged or derated. PJM has expressed its concern that these units will be unable to return to service over at least the next 48 hours, which coincides with the time period for which PJM is requesting this Order. Since these units may not promptly return to service, and in the event PJM experiences additional generating unit outages, PJM states that it may need to curtail some amount of firm load on December 24, December 25, or December 26, 2022 in order to maintain the security and reliability of the PJM system.

Description of Mitigation Measures

In its Application, PJM identifies the measures it is taking to ensure the supply of generation will continue to be sufficient to meet system demand and reserve requirements. On December 20, 2022, PJM issued a cold weather advisory in the PJM Region in anticipation of the forecasted weather conditions. Then on December 23, 2022, PJM issued

a PJM Region-wide cold weather alert which further highlighted PJM's expected need to call higher-than-normal generation resources in light of the anticipated weather.

On December 23, 2022, generating reserves diminished to a level that required PJM to declare an Energy Emergency Alert (EEA) Level 2 and take other emergency actions. PJM states that after having exhausted economic operation, PJM triggered a Maximum Generation Emergency Action to increase the PJM Region generation above the maximum economic level. Further, PJM triggered its load management reduction actions to provide additional load relief by using PJM-controllable load management programs. PJM called on demand response providers and curtailment service providers to reduce load. PJM also issued public appeals for consumers to reduce usage. PJM has continued to employ these emergency actions through December 24, 2022, and anticipates needing to continue them through the order end date that it has requested.

Since December 23, 2022, PJM has also taken additional measures to provide additional reserves, including:

- Reducing exports to neighboring regions and requested shared reserves for neighboring regions; consistent with joint operating agreements and other regulatory requirements, PJM has continued to communicate and collaborate with its interconnected neighboring systems when the demand on the PJM system has exceeded expected energy and reserve requirements and when emergency transfers were required to support PJM's interconnected neighboring systems;
- Issuing additional public conservation appeals;
- Running uneconomic generation during lower load periods to ensure their availability during peak conditions;
- Utilizing its Emergency Procedures to assist in maximizing the pumped storage hydro generation levels;
- Communicating and preparing transmission and distribution service providers to implement distribution voltage reduction measures; and
- Communicating and preparing transmission and distribution service providers to implement firm load shed.

In its Application, PJM committed to continue to take such actions, including utilizing other supply resources before calling upon any generators to operate in excess of permitting levels. According to PJM, it is nevertheless possible that the measures it has and will take may not be sufficient to avoid the need to curtail firm load in order to ensure system reliability.

Request for Order

PJM requests that the Secretary issue an order immediately, effective today, December 24, 2022, through 12:00 p.m. Eastern Time on Monday, December 26, 2022, authorizing the electric generating units identified in Exhibit A, as well as any other

generating units subject to emissions or other permit limitations in the PJM Region to operate up to their maximum generation output levels under the limited circumstances described in this Order, notwithstanding air quality or other permit limitations. The generating units (Specified Resources) that this Order pertains to are listed on the Order 202-22-4 Resources List, as described below.

ORDER

Given the emergency nature of the expected load stress, the responsibility of PJM to ensure maximum reliability on its system, and the ability of PJM to identify and dispatch generation necessary to meet the additional load, I have determined that, under the conditions specified below, additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on, among other things:

- The emergency nature of the expected load stress caused by the current cold weather event threatens to cause loss of power to homes and local businesses in the areas that may be affected by curtailments, presenting a risk to public health and safety.
- The expected shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the PJM Region demonstrate the need for the Specified Resources to contribute to the reliability of the PJM Region.
- PJM is responsible to ensure maximum reliability on its system, and, with the authority granted in this Order, its ability to identify and dispatch generation, including the Specified Resources, necessary to meet the additional load resulting from the cold weather event is enhanced.

In line with the anticipated circumstances precipitated by the cold weather event, this Order is limited to the period beginning with the issuance of this Order on December 24, 2022 through 12:00 pm Eastern Time on December 26, 2022. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the “hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable,” be consistent with any applicable environmental law and minimize any adverse environmental impacts. PJM anticipates that this Order may result in exceedance of emissions of sulfur dioxide, nitrogen oxide, mercury, and carbon monoxide emissions, as well as wastewater release limits. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes.

Based on my determination of an emergency set forth above, I hereby order:

A. From the time this Order is issued on December 24, 2022, to 12:00 pm Eastern Time on December 26, 2022, in the event that PJM determines that generation from the Specified Resources is necessary to meet the electricity demand that PJM anticipates in the PJM Region during this event, I direct PJM to dispatch such unit or units and to order their operation only as needed to maintain the reliability of the power grid in the PJM Region when the demand on the PJM system exceeds expected energy and reserve requirements. Specified Resources are those generating units set forth on the Order 202-22-4 Resource List, subject to updates directed here and as described in paragraph D, which the Department shall post on www.energy.gov.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes. Consistent with good utility practice, PJM shall exhaust all reasonably and practically available resources, including available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions, to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Specified Resources. PJM shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

In furtherance of the foregoing and, in each case, subject to the exhaustion of all available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions available to support grid reliability:

- (i) For any generation resource whose operator notifies PJM that the unit is unable, or expected to be unable, to produce at its maximum output due to an emissions or other limit in any federal environmental permit, and during the pendency of a PJM-triggered Maximum Generation Emergency Action, at any point before 12:00 Eastern Time on Monday, December 26, 2022, the unit will be allowed to exceed any such limit only during any period for which PJM has declared an Energy Emergency Alert (EEA) Level 2 or Level 3 (during which time PJM will have triggered a Maximum Generation Emergency Action), except as described in item (iii) below in certain limited circumstances in anticipation of an EEA Level 2. Once PJM declares that the EEA Level 2 event has ended, the unit would be required to immediately return to operation within its permitted limits. And at all other times, the unit would be required to operate within its permitted limits, except for the limited exceptions provided herein for operations in anticipation of an EEA Level 2 to prevent the cycling of units or facilitate the charging or pumping of other resources necessary for the EEA Level 2.
- (ii) For any generation resource whose operator notifies PJM that the unit is offline or would need to go offline at any point before 12:00 Eastern Time on Monday, December 26, 2022, due to an emissions or other limit in any

federal environmental permit, PJM may direct the unit operator to bring the unit online, or to keep the unit online, and to operate at the level consistent with its permits but subject to the exceptions set forth in this Order. In this circumstance, the operator is allowed to make all of the unit's capacity available to PJM for dispatch during any period for which PJM has declared an EEA Level 2 or 3 (during which time PJM has triggered a Maximum Generation Emergency Action), except as described in item (iii) below in certain limited circumstances in anticipation of an EEA Level 2. Once PJM declares that such an EEA Level 2 event has ended and the Maximum Generation Emergency Action is discontinued, the unit would be required to immediately return to operating at a level below the higher of its minimum operating level or the maximum output allowable under the permitted limit.

- (iii) PJM is hereby granted authority to operate the Specified Units that are combined cycle generating units in certain limited circumstances in advance of declaring an EEA Level 2, Maximum Generation Emergency, or in between such events, where such operation or continued operation of the Specified Resource is reasonably necessary to avoid shutting down and restarting the Specified Unit. PJM has represented that such cycling of units can cause reliability issues regarding restarting, delays, and increased emissions during startup. PJM is further authorized to operate the Specified Units in certain limited circumstances in advance of the declaring an EEA Level 2, Maximum Generation Emergency where such operation or continued operation of the Specified Resource is reasonably necessary to facilitate charging storage resources or pumping for pumped storage facilities that will be needed during an anticipated EEA Level 2. PJM is required to take measures to dispatch units for which cycling would otherwise be required in a manner reasonably intended to limit the duration and operating level of those units in such a way as to minimize exceedance of permit limitations consistent with the security and reliability of the PJM Region.
- (iv) To minimize adverse environmental impacts as set forth herein, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes. Consistent with good utility practice, and notwithstanding standard merit order dispatch, PJM shall exhaust all reasonably and practically available resources, including available imports, demand response and identified behind-the-meter generation resources selected to minimize an increase in emissions to the extent that such resources provide support to maintain grid reliability prior to dispatching the Specified Resources at levels above their permitted emissions levels. PJM shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

C. All operation of the Specified Resource must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. In the event that PJM identifies additional generation units that it deems necessary to operate in excess of federal environmental permitting limits in order to maintain the reliability of the power grid in the PJM Region when the demand on the PJM system exceeds expected energy and reserve requirements, PJM shall provide prompt written notice to the Department of Energy at AskCR@hq.doe.gov with the name and location of those units that PJM has identified, as well as additional notice by the same means through updating Exhibit A to its Application with such additional generation units, the fuel type of such unit, and the anticipated category of environmental impact, at 09:00 Eastern Time or 21:00 Eastern Time, whichever follows closest in time to the unit identification by PJM to the greatest extent feasible. Such additional generation unit shall be deemed a Specified Resource for the purpose of this Order for the hours prior to the required written notice to the Department updating Exhibit A, and PJM may dispatch such additional generation units, provided that if the Department of Energy notifies PJM that it does not approve of such generation unit being designated as a Specified Resource, such generation unit shall not constitute a Specified Resource upon notification from the Department. The Department shall post an updated Order 202-22-4 Resource List as soon as practicable following notification from PJM under this paragraph.

E. PJM shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time. By January 26, 2023, PJM shall report all dates between December 24, 2022, and December 26, 2022, inclusive, on which the Specified Resources were operated, the hours of operation, and exceedance of permitting limits, including sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and other air pollutants, as well as exceedances of wastewater release limits. PJM shall submit a final report by February 27, 2023, with any revisions to the information reported on January 26, 2023. The environmental information submitted in the final report shall also include the following information:

- (i) Emissions data in pounds per hour for each Specified Resource unit, for each hour of the operational scenario, for CO, NO_x, PM₁₀, VOC, and SO₂;
- (ii) Emissions data must include emissions (lbs/hr) calculated consistent with reporting obligations pursuant to operating permits, permitted operating/emission limits, and the actual incremental emissions above the permit limits;

- (iii) The number and actual hours each day that each Specified Resource unit operated in excess of permit limits or conditions, e.g., “Generator #1; December 25, 2022; 4 hours; 04:00-08:00 CT”;
- (iv) Amount, type and formulation of any fuel used by each Specified Resource;
- (v) All reporting provided under the Specified Resource’s operating permit requirements over the last three years to the United States Environmental Protection Agency or local Air Quality Management District for the location of a Specified Resource that operates pursuant to this Order;
- (vi) Additional information requested by DOE as it performs any environmental review relating to the issuance of this Order; and
- (vii) Information provided by the Specified Resource describing how the requirements in paragraph C above were met by the Specified Resource while operating under the provisions of this Order.

In addition, PJM shall provide information to the Department quantifying the net revenue in aggregate associated with generation in excess of environmental limits in connection with orders issued by the Department pursuant to Section 202(c) of the Federal Power Act.

F. PJM shall take reasonable measures to inform affected communities where all Specified Resources operate that PJM has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explains clearly what the Order allows PJM to do. At a minimum, PJM shall post a description of this Order on its website (with a link to this Order) and identify the name, municipality or other political subdivision, and zip code of Specified Resources covered by this Order, as the Specified Resources may be updated pursuant to paragraph D above. In addition, in the event that a Specified Resource operates pursuant to this Order, a general description of the action authorized by this Order will be included in any press release issued by PJM with respect to the cold weather event and will include a reference to the website posting required by the preceding sentence for further information. PJM shall describe the actions taken to comply with this paragraph in the reports delivered to the Department pursuant to paragraph E above.

G. This Order shall not preclude the need for the Specified Resource to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

H. PJM shall be responsible for the reasonable third-party costs of performing analysis of the environmental and environmental justice impacts of this Order, including any analysis conducted pursuant to the National Environmental Policy Act.

I. This Order shall be effective upon its issuance, and shall expire at 12:00 Eastern Time on Monday, December 26, 2022, with the exception of the reporting requirements in

paragraph E. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 5:30 PM Eastern Standard Time on this 24th day of December 2022.

Kathleen B.
Hogan

 Digitally signed by Kathleen B. Hogan
Date: 2022.12.24 17:38:01 -05'00'

Undersecretary of Energy for Infrastructure

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Midcontinent)
Independent System Operator)
(MISO))

Order No. 202-26-16

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 6

DOE Order No. 202-17-4

Summary of Findings

Summary of Findings

Department of Energy Order No. 202-17-4

September 14, 2017

Section 202(c) of the Federal Power Act (FPA) (codified at 16 U.S.C. § 824a(c)), through section 301(b) of the Department of Energy Organization Act (codified at 42 U.S.C. § 7151(b)), authorizes the Secretary of Energy, upon finding “that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes,” to issue an order “requir[ing] . . . such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in [the Secretary’s] judgment will best meet the emergency and serve the public interest.” 16 U.S.C. § 824a(c)(1). If the order “may result in a conflict with [an] environmental law or regulation,” then the Secretary must “ensure that such order requires generation, delivery, interchange, or transmission of electric energy only during hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable, is consistent with any applicable . . . environmental law or regulation and minimizes any adverse environmental impacts.” *Id.* § 824a(c)(2). Orders issued under FPA section 202(c) “that may result in a conflict with [an] environmental law or regulation” expire 90 days after they are issued, but the Secretary “may renew or reissue such order[s] . . . for subsequent periods, not to exceed 90 days for each period, as [the Secretary] determines necessary to meet the emergency and serve the public interest.” *Id.* § 824a(c)(4)(A).

The Department’s regulations implementing FPA section 202(c) define the term “emergency” to mean, among other situations, “a specific inadequate power supply situation.” 10 C.F.R. § 205.371. The regulations do not exhaustively list what qualifies as an emergency, but they note specifically that “[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency as contemplated in these regulations.” *Id.*

On June 13, 2017, PJM filed a *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Order Application) (included in the docket¹ of this Order) with the Department “to preserve the reliability of [the] bulk power transmission system in the North Hampton Roads area.” Virginia Electric and Power Company² (Dominion), the electric utility serving the area, owns the coal-fired, power generating Units 1 and 2 at the Yorktown Power Station in Yorktown, Virginia. In November 2011 and October 2012, Dominion notified PJM of its plan to deactivate Units 1 and 2, respectively, effective December 31, 2014, because the units were not equipped to

¹ The docket of this Order is available at <https://www.energy.gov/oe/downloads/federal-power-act-section-202c-dominion-energy-virginia-june-2017>.

² See Dominion Energy, Inc., Form 10-Q filing, at 1 (Aug. 3, 2017), included in the docket of this Order.

comply with the Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards (MATS), 40 C.F.R. part 63 subpart UUUUU. On June 24, 2014, pursuant to 40 C.F.R. § 63.6(i)(4)(i)(A), the Virginia Department of Environmental Quality granted Dominion a one-year MATS compliance extension for Yorktown Units 1 and 2.

On April 16, 2016, pursuant to section 113(a) of the Clean Air Act, 42 U.S.C. § 7413(a)(3) and (4), the EPA issued an Administrative Compliance Order (ACO) through April 15, 2017. The ACO implemented a 2011 MATS Enforcement Policy regarding issuance of section 113(a) administrative orders to sources that are unable to comply with the MATS but that may need to operate for up to a year to address a specific and documented reliability concern. The 2011 MATS Enforcement Policy was limited in application to units critical for reliability purposes. The EPA found that operation of Yorktown Units 1 and 2 met the policy criteria, as verified by the Federal Energy Regulatory Commission (FERC). Dominion has not achieved full compliance with the MATS for Yorktown Units 1 or 2 since the ACO expired, and section 113(a) of the Clean Air Act bars further compliance extensions.

Since Dominion's decision to retire the coal-fired Yorktown units, PJM has planned for their permanent deactivation by including required transmission upgrades in its own Regional Transmission Expansion Planning Process. PJM is subject to federal reliability standards enforced by the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization designated by FERC. PJM holds the highest-level reliability responsibilities for the system it manages as a certified Reliability Coordinator, Balancing Authority, and Transmission Operator. PJM is also registered with NERC as a Planning Coordinator and Transmission Planner, among other functions. NERC Compliance Registry Active Entities List (updated Sept. 7, 2017), included in the docket of this Order. PJM applies reliability criteria to evaluate transmission system conditions and then develops the transmission solutions needed to ensure compliance with the reliability standards. The PJM Board of Managers approves those solutions in a Regional Transmission Expansion Plan (RTEP). Through its Transmission Expansion Advisory Committee (TEAC) and Sub-Regional RTEP Committees, PJM works with stakeholders throughout the RTEP's development. PJM Manual 14B, "Regional Planning Process," included in the docket of this Order. The PJM Board of Managers approved the transmission upgrades necessitated by the retirement of Yorktown Units 1 and 2 on May 17, 2012. TEAC Recommendations to the PJM Board (PJM Staff Whitepaper), May 2012, at 12, included in the docket of this Order.

PJM's approved solution was the Skiffes Creek Transmission Project, which consists of three components: a 500kV line, a 230kV line rebuild, and a new switching station. United States Army Corps of Engineers (Army Corps), Memorandum for the Record re: Department of the Army Environmental Assessment and Statement of Findings for the Above-Referenced Standard Individual Permit Application, CENAO-WR-RS (NAO-2012-00080 / 13-V0408), at 1, included in the docket of this Order. A

number of issues in the North Hampton Roads area, many of which are interrelated, needed to be addressed to avoid overloading transmission lines with too much power, as detailed in PJM's Deactivation Study. Yorktown Units 1 and 2 Generator Deactivation Notification: Deactivation Study Results – updated June 26, 2017 (PJM Deactivation Study), included in the docket of this Order. *See also Va. Elec. & Power Co.*, Commission Comments on Requests for EPA Administrative Orders, Docket No. AD16-11-000, 153 FERC ¶ 61,265 at PP 14-16 (2015).

PJM completed a series of analyses consistent with RTEP procedures, finding that only the Skiffes Creek Transmission Project—and none of the stakeholder-proposed alternatives—addressed the full range of potential reliability violations. Order Application, app. I, at 16. For example, reliance on operation of the oil-fired Yorktown Unit 3 generator would not address thermal overload and voltage violations on the 230kV and 115kV bulk electric system that PJM identified because of significant environmental operating restrictions and other plant operation constraints associated with that unit, including an 8 percent capacity factor limitation. *See id.*, app. II, at 18. As a result, PJM did not recommend reliance on Yorktown Unit 3 as a sustainable alternative solution to the identified reliability criteria violations. *Id.*

As part of PJM's analyses, Dominion transmission staff provided PJM with an analysis of system needs as well as potential solutions to the retirement of generating units at Yorktown and elsewhere. Dominion Update to Retirement Study Results (Mar. 10, 2012), included in the docket of this Order. Dominion's analysis, which was based on PJM's initial determination of reliability criteria violations that needed to be addressed, was independently validated by PJM and publicly vetted through the PJM stakeholder process before PJM staff recommended that the Board of Managers approve the Skiffes Creek Transmission Project. PJM Staff Whitepaper at 12, included in the docket of this Order.

PJM, as the Regional Transmission Organization (RTO) responsible for transmission system operation across multiple states, including Virginia, maintains its expert determination that the Skiffes Creek Transmission Project is the most effective and efficient solution to address the identified reliability criteria violations. Order Application, app. I, at 16. As recently as March 1, 2017, PJM provided the Army Corps with an analysis of proposed alternatives and found that none of them sufficiently resolved the identified violations. Letter to Col. Jason E. Kelly, U.S. Army Corps of Engineers (Mar. 1, 2017), included in the docket of this Order. PJM's subsequent RTEP materials reaffirm the need for the Skiffes Creek Transmission Project, even considering the updated, steadily rising load forecasts in the recently released 2017 PJM Load Forecast Report (included in the docket of this Order). *See* PJM Interconnection, L.L.C., 2017 RTEP Process Scope & Input Assumptions, rev. 1, at 25-27 (Aug. 3, 2017), included in the docket of this Order.

Construction of the Skiffes Creek Transmission Project began in July 2017 and is expected to take approximately 18-20 months. *Order No. 202-17-2 Renewal Application Filing* (Renewal Application) at 3. Until the Project is completed, a plan known as the North Hampton Remedial Action Scheme (RAS) remains in effect. According to NERC's Glossary of Terms, a RAS is "[a] scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation ([megawatts] and [megavolt amperes (reactive)]), tripping load, or reconfiguring a System(s)." Glossary of Terms Used in NERC Reliability Standards (updated Aug. 1, 2017), at 24, included in the docket of this Order.

To preserve the grid's reliability, the North Hampton RAS would allow PJM, the grid operator, to drop load—that is, shut off power to certain customers—to prevent voltage collapse. Dominion presented this RAS to PJM in January 2017, and the SERC Reliability Corporation, the NERC-delegated regional reliability enforcement entity, approved it that same month. See Dave Rees, *Dominion Virginia Power Sets Plan for Emergency Blackouts*, Daily Press, Jan. 13, 2017, included in the docket of this Order. If Yorktown Units 1 and 2 were unavailable, many N-1-1 contingencies could result in voltage collapse and thermal overloads. New Remedial Action Scheme, North Hampton RAS (Presentation to PJM), at 4, included in the docket of this Order; PJM Deactivation Study, included in the docket of this Order. According to FERC, "An N-1-1 contingency is a sequence of events consisting of an initial loss of a single generator or transmission element, followed by system adjustment, followed by another loss of a single generator or transmission element." *Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. AD14-14-000, 153 FERC ¶ 61,221 at P 30 n.61 (2015).

The North Hampton RAS is on standby for use at PJM's discretion. If PJM detects the loss of certain facilities, it could trip the remaining feeds to the Yorktown area and drop service to approximately 150,000 customers, preventing voltage collapse. Rotating outages would follow until the system returns to normal operating parameters. New Remedial Action Scheme, North Hampton RAS (Presentation to PJM), at 6, included in the docket of this Order. According to U.S. Census estimates, the region PJM identifies as the North Hampton Roads load area in its Order Application had a population of more than 660,000 as of July 2016. At a minimum, rotating outages under the RAS would therefore impact, directly or indirectly, several hundred thousand people. United States Census Bureau, QuickFacts database, available at <https://www.census.gov/quickfacts/fact/table/US/PST045216>.

On July 3, 2017, the Army Corps issued a permit to Dominion for the Skiffes Creek Transmission Project pursuant to section 10 of the Rivers and Harbors Act of 1899 (33 U.S.C. § 403) and section 404 of the Clean Water Act (33 U.S.C. § 1344). On July

10, 2017, Dominion commenced construction of the Skiffes Creek Transmission Project. Renewal Application at 3.

On August 24, 2017, PJM filed its Renewal Application with DOE. The filing included all reports required by Order No. 202-17-2 (included in the docket of this Order). PJM said that construction of the Project was still expected to take 18-20 months, and that periodic transmission outages would be necessary to proceed apace with the Project. The same day, Dominion wrote to the Department that it “agrees with the Renewal Application and will operate in accordance with its provisions.” Further, Dominion acknowledged that a 202(c) order “is not a long term solution to the reliability issues in the North Hampton Roads area on the Virginia Peninsula.” The Skiffes Creek Transmission Project, underway as of July 2017, is the long-term solution.

On September 7, 2017, the Department received comments from Sierra Club opposing PJM’s renewal request. On September 13, 2017, the Department received an answer to Sierra Club’s comments from PJM. Both documents are included in the docket of this Order.

Discussion

Order No. 202-17-2 directs operation of Yorktown Units 1 and 2 as needed to address reliability issues, subject to a dispatch methodology submitted to the Department for review. The reliability issues noted in Order No. 202-17-2 were described as Scenario One, increased load due to weather-related temperature extremes, and Scenario Two, decreased transmission capacity required by the RTEP upgrade. Scenario Two was contemplated but not yet applicable when Order No. 202-17-2 was issued because the Army Corps permit application for the Skiffes Creek Transmission Project was still pending. On July 3, the Army Corps issued Permit No. NAO-2012-00080, resulting in the potential need to operate Yorktown Units 1 and 2 to address both Scenario One and Two reliability issues. To date, in accordance with Order No. 202-17-2, PJM has directed operation of Yorktown Units 1 and/or 2 for all or part of 13 days. PJM Interconnection, L.L.C., Report on Yorktown Units 1 and 2 Operations Pursuant to Order No. 202-17-2, Attachment 1, included in the docket of this Order; Telephone call to Steven Pincus, Associate General Counsel, PJM, Sept. 11, 2017.

Scenario One applies when load conditions exceed a certain threshold due to local transmission issues that would cause PJM to operate the system outside its normal operating parameters.³ Weather-related temperature extremes are one example of such a local transmission issue. Scenario Two is also triggered when load conditions exceed a certain threshold, but the threshold is lowered depending on the particular construction-related transmission outages in effect as the Skiffes Creek Transmission Project is built.

³ Exact load thresholds were submitted as critical electric infrastructure information and are thus not described here so as not to provide vulnerability information on critical infrastructure.

Because the Project minimizes environmental impacts by utilizing existing transmission line rights-of-way to the extent possible, portions of existing transmission lines must be taken offline for upgrades. Under either scenario, when the relevant thresholds are exceeded, to prevent system overload and uncontrolled power disruptions, PJM must implement the North Hampton RAS. The only sufficient alternative to the RAS and its resulting outages for up to approximately 150,000 customers is the emergency operation of Yorktown Units 1 and 2. The demand response available to PJM is a small fraction of the load threshold and is “not sufficient to ensure reliable service.” Order Application, app. II, at 18. Likewise, Dominion has limited demand-side management and curtailment capabilities, insufficient for reliability purposes even when fully deployed. *See id.*, app. III, at 21.

Activating the RAS would immediately interrupt service to load in the North Hampton Roads area. PJM asserts that, according to the RAS, during certain high load conditions, this “load shedding” could result in the loss of roughly 950 MW of electric power—that is, the loss of service to over 150,000 North Hampton Roads area customers. Order Application at 9. This service interruption could last hours or even days. *See* North Hampton RAS Presentation to PJM, at 8, included in the docket of this Order. Activating the RAS is not a gradual approach that presents a wide range of likely impacts; it is an extreme measure with immediate consequences to 150,000 customers. While the RAS is designed to prevent more catastrophic, uncontrolled grid impacts from occurring, load shedding of this magnitude is significant, and would trigger mandatory reporting both to DOE and FERC. DOE Form OE-417 requires reporting within one hour for “[l]oad shedding of 100 Megawatts or more implemented under emergency operational policy,” and within six hours for “[l]oss of electric service to more than 50,000 customers for 1 hour or more.” This is the same level of reporting triggered by a cyber or other hostile attack on grid resources. Form OE-417, Electric Emergency Incident and Disturbance Report, https://www.oe.netl.doe.gov/docs/OE417_Form_03312018.pdf. Similarly, FERC and NERC mandate notification for a variety of serious events including when a bulk electric system emergency triggers automatic load shedding of 100 MW or more, as in the RAS. *See* North American Electric Reliability Corporation, Reliability Standard EOP-004-3 (Event Reporting), http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-004-3&title=Event%20Reporting.

To underscore the potential impact of RAS activation, the estimated 150,000 impacted customers are counted by meter, not individual. One or more meters could translate to large household or commercial or industrial facilities, including those critical to health and safety systems. Whether counted as 150,000 or that amount multiplied several times over, the anticipated impact of this emergency situation is on par with or exceeds the impacts described in prior 202(c) orders. *Crisp Cnty. Power Comm’n v. Ga. Power Co.*, 35 FPC 629, 630-31 (1966) (ordering interconnection to prevent, in part,

outages lasting more than an hour and affecting 500 to 2,000 customers on Crisp County, Georgia's system). *City of Cleveland, Ohio v. Cleveland Elec. Illuminating Co.*, 47 FPC 747, 749 (1972) (ensuring reliable service was provided to the approximately 20% of the city's consumers). Cleveland's 1970 Census-reported population was 750,903, suggesting that just over 150,000 individuals were affected by the 1972 202(c) order. See <https://www.census.gov/population/www/documentation/twps0027/tab20.txt>. As described earlier, the U.S. Census estimated the population of the North Hampton Roads load area at nearly 661,000 people just over a year ago.

A benefit of the planning efforts mandated by federal reliability standards is that entities such as PJM can accurately forecast the impacts to the bulk power system in steady-state and various contingency event situations. Thus, as reliability planning continues to mature, there should be fewer electric energy shortages that take bulk power system owners, operators, and regulators by surprise. That planners can identify conditions under which shortages may occur, however, does not rule out electric energy shortages constituting emergencies under FPA section 202(c) and the Department's implementing regulations. It is impossible to plan for every contingency, and challenges may arise even when implementing the most prudent plans. FPA section 202(c) affords the Secretary of Energy discretion in finding when an emergency exists and how best to meet the emergency and serve the public interest.

Here, an emergency exists due to the imminent possibility of implementing the North Hampton RAS under a range of both steady-state and contingency events, including potential transmission congestion preventing the delivery of available generation to the North Hampton Roads area. PJM Deactivation Study at 1-2, included in the docket of this Order. The RAS would leave approximately 150,000 customers without power, including residential, industrial, commercial, health and safety facilities, major national defense, and educational institutions. See Order Application, app. IV, at 30-31. That creates serious health and safety issues. Issuance of today's Order meets the emergency and serves the public interest.

In these circumstances, transmission outages, like those contemplated for or otherwise in connection with the construction of the Skiffes Creek Transmission Project, constitute an emergency for purposes of a section 202(c) order. As stated earlier, the Department's implementing regulations, in their current form since 1981, contemplate that "[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities [may create] an emergency." 10 C.F.R. § 205.371. The regulations add that "[i]n such cases, the impacted 'entity' will be expected to make firm arrangements to resolve the problem until new facilities become available, so that a continuing emergency order is not needed." *Id.* PJM, the impacted entity in this case, requested today's Order. Through the RTEP, PJM made firm arrangements to resolve the problem through the Skiffes Creek Transmission Project, which is now permitted and under construction. That construction was delayed due to events beyond

PJM's control has no bearing on the likelihood of power outages for 150,000 customers. Such a power loss event would also constitute an emergency as contemplated by FERC in its Public Utility Regulatory Policies Act of 1978 regulations, which define "system emergency" as "a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property." 18 C.F.R. § 292.101(b)(4). The risk faced by 150,000 customers will continue, assuming the Skiffes Creek Transmission Project construction schedule is met, for approximately another 18 months. Today's Order is limited in time and specifically tailored to address an emergency contemplated both in the authorizing statute and the Department's implementing regulations.

Between 2005 and 2007, DOE issued orders under similar circumstances, directing the Mirant Potomac River Generation Station to operate until two new 230kV transmission lines could be built to ensure reliability to a portion of the District of Columbia. See Order No. 202-5-3 (relying on DOE regulatory definition of emergency as including extended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities). In a series of orders under FPA section 202(c), the Secretary ordered operation of the generation units while the two existing 230kV lines that supplied the central District of Columbia area were temporarily and sequentially removed from service to connect the new lines. Neither the problems leading up to the closure of the generating units nor the need for a particular transmission solution were unexpected. Nevertheless, the Department found that imminent power shortages, faced if contingency events occurred, constituted an emergency under the Federal Power Act. Order Nos. 202-5-3, 202-6-1, 202-6-2, 202-7-1, and 202-7-2.

In this matter, the likelihood of RAS activation is not theoretical. While Order No. 202-17-2 was in effect, PJM had to call upon Yorktown Units 1 and/or 2 on 13 days over three months. Absent Order No. 202-17-2, the RAS would have been activated instead. The alternatives available to PJM and Dominion are not sufficient to ensure reliability without available capacity from Yorktown Units 1 and 2. As described, PJM and Dominion cannot mobilize adequate alternatives to counter the loss of transmission during construction of the Skiffes Creek Transmission Project. For example, demand response resources, while potentially helpful at the margin, are insufficient to address either Scenario One or Scenario Two. See Order Application, app. II, at 18. Further, PJM's recent RTEP Input Assumptions and Scope Whitepaper indicates that Dominion theoretically has up to 130 MW of distributed solar generation available during the summer. 2017 RTEP Process Scope and Input Assumptions, rev. 1, tbl.3.2, at 18 (Aug. 3, 2017), included in the docket of this Order. Outside of ramp-up and ramp-down times, each Yorktown Unit typically ran at 100 MW output or higher, day or night, when operational while Order No. 202-17-2 was in effect. PJM Interconnection, L.L.C., Report on Yorktown Units 1 and 2 Operations Pursuant to Order No. 202-17-2, Attachment 1. Distributed generation is an intermittent resource; even under ideal conditions, with full-capacity, daytime generation and load reduction at the height of the

summer, distributed generation generally would still not have offset the baseload generating capacity needed to ensure reliability on the North Hampton Roads area grid. And any flexibility for scheduling the Skiffes Creek Transmission Project's construction during historically low-load periods ended when the EPA ACO expired, as expeditious completion of the Project is now the priority. Therefore, even if PJM and Dominion made full use of available alternatives, capacity from Yorktown Unit 1, 2, or both would still be necessary to meet the emergency and serve the public interest.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law or regulation be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable, [be] consistent with any applicable . . . environmental law or regulation and minimize[] any adverse environmental impacts." Certain load conditions may necessitate operation of Yorktown Units 1 and 2.

To minimize the hours of operation and adverse environmental impacts, the Order contains certain limitations. First, DOE maintains consistency with EPA's approach in the 2016 ACO by authorizing operation of Yorktown Units 1 and 2 only when called upon by PJM for reliability purposes. The Department consulted with EPA and has reviewed data provided by PJM and Dominion on operations, air emissions, and water usage. This Order will continue the operational limitations described in EPA's above-referenced ACO, AED-CAA-113(a)-2016-0005. Second, DOE requires that PJM and Dominion, consistent with good utility practice, first exhaust all reasonably and practically available resources, including demand response and behind-the-meter generation resources, before operating Yorktown Units 1 and 2. Third, DOE requires continued compliance with the June 27 dispatch methodology, which was reviewed by the Department, and which remains subject to continuing oversight by the Department. In particular, the dispatch methodology establishes Yorktown Units 1 and 2 commitment procedures, describes the utilization and trip conditions of the North Hampton RAS for mitigating congestion on the Virginia Peninsula or North Hampton Roads area, and describes Dominion's mitigation options for the existing James River tower contingency. The dispatch methodology is an operating protocol that limits the ability of PJM to dispatch Yorktown Units 1 and 2 only when needed to mitigate reliability issues associated with scheduled and emergency transmission outages directly related to the Skiffes Creek Transmission Project and other local transmission issues. The EPA ACO recognized that such a dispatch methodology, under which PJM determines when the Yorktown units are needed for reliability issues, serves the objective of minimizing emissions. ACO at 8-9, included in the docket of this Order. Fourth, to track when Yorktown Units 1 and 2 are operated to maintain grid reliability and to monitor associated air emissions and water usage, reports will be required every two weeks going forward. If the Department becomes concerned with PJM or Dominion's compliance with this Order, enforcement actions are available, up to and including termination of the underlying order.

While DOE has constrained PJM's operations with regard to Yorktown Units 1 and 2, it is necessary to preserve reasonable discretion for PJM, as a Transmission Operator, to address the second-to-second operational challenges of grid management. This follows DOE's practice in earlier orders issued under FPA section 202(c), which prioritized reliability concerns as identified and assessed by the operator. For example, Order No. 202-02-1 (Aug. 16, 2002) ordered Cross-Sound Cable Company, LLC to operate a cable across Long Island Sound, limiting "transmission and delivery of . . . electric capacity and/or energy [to that] necessary in the judgment of the New York Independent System Operator [ISO] to meet the supply and essential reserve margin needs of the Long Island Power Authority [LIPA]," but only "in order for LIPA to serve its firm retail customers after it has implemented all available load reduction measures consistent with good utility practice." Order No. 202-03-1 (Aug. 14, 2003) directed operation of the same cable, but specifically ordered the New York ISO and ISO New England to require Cross-Sound Cable Company to operate the cable. That order also required both RTOs to "consult with each other and with appropriate reliability organizations." Today's Order similarly requires PJM to identify and mitigate reliability issues in accordance with DOE's specified operational limitations.

In considering renewal or reissuance of an order under FPA section 202(c) that may conflict with an environmental law or regulation, DOE is required to "consult with the primary Federal agency with expertise in the environmental interest protected by such law or regulation" and to include "conditions as such Federal agency determines necessary . . . to the extent practicable." 16 U.S.C. § 824a(c)(4). The EPA is the primary federal agency in this case with expertise in the protected environmental interest, specifically MATS and section 316(b) of the Clean Water Act, and the Department consulted with EPA after receiving the Renewal Application. Email from Acting Assistant Administrator Starfield, Office of Enforcement and Compliance Assurance, to Acting Under Secretary for Science and Energy Hoffman (Sept. 11, 2017), included in the docket of this Order. After consulting with EPA, and consistent with that consultation, the Department found that the only appropriate short-term emissions limitation on Yorktown Units 1 and 2 would be to curtail operating hours to the maximum extent practical for reliability purposes.

Pursuant to the National Environmental Policy Act of 1969, the Department has determined that issuance of this Order fits within the category of actions included in Categorical Exclusion (CX) B4.4 and otherwise meets the requirements for application of a CX. The Order fits within the category of actions because it authorizes "[p]ower marketing services and power management activities (including, but not limited to, storage, load shaping and balancing, seasonal exchanges, and other similar activities), provided that the operations of generating projects would remain within normal operating limits." Records of Categorical Exclusion Determination, Order No. 202-17-4, Sept. 11, 2017, included in the docket of this Order.

Summary of Findings for Department of Energy Order No. 202-17-4

For the reasons stated above, the Secretary of Energy finds that an emergency exists threatening imminent electric energy shortages, and that this Order is necessary to address the emergency and serve the public interest in the North Hampton Roads area. The limitations on operation set forth in Order No. 202-17-4 and outlined above are, to the maximum extent practicable, consistent with applicable environmental laws or regulation and minimize any adverse environmental impacts, and the reporting requirements for operations and estimated emissions ensure transparency of implementation.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Midcontinent)
Independent System Operator)
(MISO))
_____)

Order No. 202-26-16

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 7

DOE Order No. 202-02-1



Department of Energy

Washington, DC 20585

Order No. 202-02-1

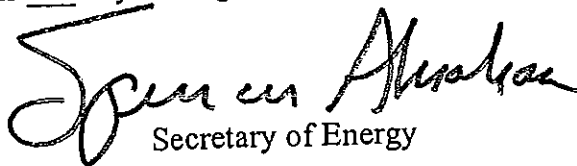
Pursuant to the authority vested in me by section 202(c) of the Federal Power Act, 16 U.S.C. 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. 7151(b), I hereby determine that an emergency exists on Long Island in the State of New York due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, a shortage of facilities for the transmission of electric energy and other causes, and that issuance of this order will alleviate the emergency and serve the public interest. Based on this determination, I hereby order:

From the effective date and time of this order until 12:01 a.m. Eastern Daylight Time, October 1, 2002, Cross-Sound Cable Company, LLC is directed to operate the Cross-Sound Cable and related facilities connecting substations in New Haven, Connecticut and Shoreham, Long Island, New York, to transmit and deliver electric capacity and/or energy when, as and in such amounts as may be scheduled and purchased by the Long Island Power Authority (LIPA), and to take such actions as are necessary in order to enable it to do so, including but not limited to energizing and continuing to energize the facilities of Cross-Sound Cable Company, LLC; *provided*, that this order otherwise shall be limited to requiring the transmission and delivery of such electric capacity and/or energy as is necessary in the judgment of the New York Independent System Operator to meet the supply and essential reserve margin needs of LIPA, in order for LIPA to serve its firm retail customers after it has implemented all available load reduction measures consistent with good utility practice, including curtailing and/or terminating service to interruptible customers, public appeals for conservation, reducing 30 minute reserves to zero, and implementing voltage reductions; *and provided further*, that prior to exercising its judgment as required by this order, the New York Independent System Operator must consult with ISO New England, Inc. to ensure that the scheduling of such electric capacity and/or energy will not violate system operating criteria, and the New York Independent System Operator should, as practicable, consult with appropriate reliability organizations. If necessary, just and reasonable terms for the transmission and delivery of electric capacity and/or energy pursuant to this order, including the compensation therefor, shall be established by a supplemental order issued pursuant to Federal Power Act section 202(c).

Nothing in this order shall preclude use of the energized Cross-Sound Cable and its related facilities connecting substations in New Haven, Connecticut and Shoreham, Long Island, New York, to transmit and deliver electric capacity and/or energy from Long Island to Connecticut or from Connecticut to Long Island in accordance with the operating and scheduling protocols and decisions of the New York Independent System Operator and ISO New England, Inc.

This order shall be effective upon its issuance.

Issued in Washington, D.C. at 2:38PM this 16th day of August, 2002.


Secretary of Energy



BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Midcontinent)
Independent System Operator)
(MISO))
_____)

Order No. 202-26-16

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 8

Cooke Email to Alle-
Murphy

-----Original Message-----

From: Alle-Murphy, Linda
Sent: Wednesday, December 28, 2005 9:05 AM
To: Mansueti, Lawrence
Subject: Re: Order No. 202-05-3

Dear Mr. Mansueti,

I am an associate at Schnader Harrison Segal and Lewis, working together with John Britton, who represents the City of Alexandria in the Mirant Power Plant matter. I have a few procedural questions regarding the application for rehearing.

According to Section VI.H. of Order No. 202-05-3, applications for rehearing in this matter should be addressed to you. Section VI.H. cites to 16 U.S.C. Section 825(l), which refers to the "Commission" (FERC). I am just seeking to confirm that Section 825(l) also applies to this DOE proceeding.

Also, are 10 CFR Section 1003.1 et seq., Office of Hearings and Appeals Procedural Regulations applicable to this proceeding (e.g. re service requirements, etc.) If not, are there other procedural rules that apply to this proceeding?

Thank you very much for your assistance! You may respond by return e-mail or, if that is not convenient for you, by telephone or fax.

Linda Alle-Murphy
Linda B. Alle-Murphy
Schnader Harrison Segal & Lewis LLP
1600 Market Street, Suite 3600
Philadelphia, PA 19103-7286

From: Cooke, Lot
Sent: Friday, December 30, 2005 8:51 AM
To: 'LAlle-Murphy@Schnader.com'
Subject: Rehearing procedures for DOE Order No. 202-05-3

Dear Ms. Alle-Murphy:

In response to your emailed question to Mr. Mansueti--

The DOE Organization Act transferred the authority of the Federal Power Commission to the Secretary, except for authority over rates and charges for the transmission and sale of electric energy, which was transferred to FERC. Federal Power Act (FPA) Section 202(c) emergency authority was generally and specifically given to the Secretary.

An order issued under the FPA is only reviewable pursuant to the rehearing provisions contained in section 313 of the FPA, so that is the applicable provision under which to seek rehearing of the December 20, 2005 order.

The DOE regulations on emergency orders, 10 CFR section 205.370, et seq., do not have a specific rehearing section, but a party seeking rehearing can look for procedural guidance to FERC's Rules of Practice and Procedure, 18 CFR Part 385. In particular the rehearing regulations contained at 18 CFR section 385.713 and the service requirement contained at 18 CFR section 385.2010. The Office of Hearings and Appeals procedures are not applicable as the Secretary will make the rehearing decision pursuant to FPA section 313.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Midcontinent)
Independent System Operator)
(MISO))

Order No. 202-26-16

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 9

Order Approving Campbell Settlement Agreement and Settlement Agreement

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of CONSUMERS	)	
ENERGY COMPANY for approval of its integrated	)	
resource plan pursuant to MCL 460.6t and for other	)	Case No. U-21090
relief.	)	
_____	)	

At the June 23, 2022 meeting of the Michigan Public Service Commission in Lansing,
Michigan.

PRESENT: Hon. Daniel C. Scripps, Chair
Hon. Tremaine L. Phillips, Commissioner

ORDER APPROVING SETTLEMENT AGREEMENT

I. Procedural History

On June 30, 2021, Consumers Energy Company (Consumers) filed an application, together with supporting testimony and exhibits, pursuant to: (1) Section 6t of Public Act 341 of 2016 (Act 341), MCL 460.6t; (2) the November 21, 2017 order in Case No. U-18418, Exhibit A, which approved the Michigan Integrated Resource Planning Parameters; (3) the December 20, 2017 order in Case Nos. U-15896 *et al.*, Exhibit A, which approved the Integrated Resource Plan (IRP) Filing Requirements; and (4) the February 18, 2021 order in Case Nos. U-20633 *et al.*, which adopted additional modeling scenarios to assist in achieving the objectives of Executive Directive 2020-10 (ED 2020-10) and Governor Gretchen Whitmer’s MI (Michigan) Healthy Climate Plan.

On July 22, 2021, a prehearing conference was held before Administrative Law Judge Sally L. Wallace (ALJ). Intervenor status was granted to the Michigan Environmental Council, Natural

Resources Defense Council, Inc., and Sierra Club (collectively, MNS); the Michigan Department of Attorney General (Attorney General); the Great Lakes Renewable Energy Association, Inc. (GLREA); the Environmental Law and Policy Center of the Midwest, Ecology Center, Inc., Union of Concerned Scientists, Inc., and Vote Solar (collectively, the Clean Energy Organizations (CEOs)); Hemlock Semiconductor Operations LLC (HSC); Cadillac Renewable Energy, LLC, Genesee Power Partner Limited Partnership, Decker Energy-Grayling, Inc., Hillman Power Company, L.L.C., Tondu Corporation, Viking Energy of Lincoln, LLC, and Viking Energy of McBain, LLC, (collectively, the Biomass Merchant Plants (BMPs)); the Association of Businesses Advocating Tariff Equity (ABATE); Energy Michigan; Michigan Energy Innovation Business Council, Institute for Energy Innovation, and Clean Grid Alliance (jointly, EIBC/IEI/CGA); Midland Cogeneration Venture Limited Partnership (MCV); Michigan Electric Transmission Company, LLC (METC); Wolverine Power Supply Cooperative, Inc. (WPSC); Michigan Public Power Agency (MPPA); Residential Customer Group (RCG); Citizens Utility Board of Michigan (CUB); and Urban Core Collective (UCC). Permissive intervention was granted to the Mackinac Center for Public Policy (Mackinac). Consumers and the Commission Staff (Staff) also participated in the proceeding.

The ALJ issued a Proposal for Decision (PFD) on March 7, 2022. On or before March 21, 2022, exceptions were filed by Consumers, HSC, the Attorney General, the Staff, MNS, the CEOs, GLREA, Mackinac, ABATE, the BMPs, UCC, EIBC/IEI/CGA, and WPSC. On March 28, 2022, replies to exceptions were filed by Consumers, Energy Michigan, HSC, the Attorney General, the Staff, MNS, the CEOs, GLREA, ABATE, the BMPs, UCC, EIBC/IEI/CGA, and WPSC.

On April 20, 2022, Consumers entered into a settlement agreement with the following parties: the Staff, MNS, the Attorney General, the CEOs, UCC, CUB, HSC, EIBC/IEI/CGA, METC, and

GLREA. The settlement agreement recommends approval of Consumers' proposed course of action (PCA) with changes and covers issues such as: the acquisition of new resources; investments in demand response (DR), conservation voltage reduction (CVR), and energy waste reduction (EWR); deployment of energy storage; retirement of certain coal-fired generation units and associated decommissioning costs; a financial compensation mechanism (FCM); avoided cost methodology under the Public Utility Regulatory Policies Act of 1978 (PURPA); and implementation of competitive bidding. MPPA, MCV, RCG, and ABATE did not join the settlement, but offered statements of non-objection.

On April 20, 2022, Consumers and the Staff jointly filed a motion to extend the statutory deadline found in Section 6t(7) of Act 341, MCL 460.6t(7). In its April 25, 2022 order in the present case (April 25 order), the Commission granted the joint motion and extended the deadlines for the Commission's 300-day and 360-day orders. In addition, the Commission set a tentative schedule for the remainder of this proceeding. *See*, April 25 order, p. 5.

On May 4, 2022, Energy Michigan, Mackinac, WPSC, and the BMPs filed responses objecting to the settlement agreement. MNS, the CEOs, Energy Michigan, the Staff, the BMPs, and WPSC filed direct testimony in the contested settlement phase of this proceeding on May 9, 2022. MNS, the Staff, EIBC/IEI/CGA, WPSC, the BMPs, Consumers, and the CEOs filed rebuttal testimony on May 13, 2022. Initial briefs on the contested settlement were filed by MNS, Mackinac, EIBC/IEI/CGA, the Attorney General, the CEOs, HSC, the Staff, Consumers, CUB, the BMPs, and WPSC on May 25, 2022, and reply briefs were filed by MNS, the Staff, the CEOs, Consumers, WPSC, and the BMPs on May 27, 2022. UCC filed a letter in support of the settlement agreement on May 25, 2022. The evidentiary record in this contested settlement proceeding consists of 315 pages of transcript and 22 exhibits, all of which appear in Volume 10

of the transcript. Unless otherwise noted, all citations to briefing in this order refer to the briefing in the contested settlement phase of this case and not the contested IRP phase.

II. Applicable Law

Act 341 requires the Commission to approve an IRP if the proposed IRP “represents the most reasonable and prudent means of meeting the electric utility’s energy and capacity needs” based on whether the proposed plan: (1) appropriately balances a series of statutorily listed factors; (2) uses a workforce comprised of residents of this state to the extent practicable in the completion of construction or investment in new or existing capacity resources; and (3) meets the requirements of subsection 6t(5) of Act 341, which enumerates the information to be included in an IRP. MCL 460.6t(8).

In addition, Rule 431 of the Michigan Administrative Code, Mich Admin Code, R 792.10431, governs proceedings before the Commission where a settlement is filed. Pursuant to Rule 431(5)(a)-(c), the Commission may approve a contested settlement agreement when the Commission determines the following conditions are met: (1) objecting parties have been given a reasonable opportunity to present evidence and arguments in opposition to the settlement agreement, (2) the public interest is adequately represented by the parties who entered into the settlement agreement, and (3) the settlement agreement is in the public interest, represents a fair and reasonable resolution of the proceeding, and is supported by substantial evidence on the record as a whole.

III. Proposed Settlement Agreement

Under the terms of the settlement agreement, the parties to the settlement (settlement parties) agree that Consumers’ PCA, as modified, should be approved by the Commission as the most reasonable and prudent means of meeting the company’s energy and capacity needs for the 5-year,

10-year, and 15-year time horizons as required by Sections 6t(3) and 6t(8)(a) of Act 341, MCL 460.6t. Settlement Agreement, p. 3. The settlement parties agree that Consumers will file its next IRP consistent with the requirements of Section 6t. *Id.* The settlement agreement, attached to this order as Exhibit A, contains the following provisions relevant to the arguments in the contested settlement proceeding:

The settlement agreement provides that Consumers' PCA shall include the proposed purchase of the New Covert Generating Facility (Covert plant) in 2023 but shall not include the ownership of the Dearborn Industrial Generation Plant (DIG), the Livingston Generating Station (Livingston), and the Kalamazoo River Generating Station (Kalamazoo) (collectively, CMS plants). Settlement Agreement, pp. 2-3. The parties agree that the identified capital costs that Consumers will incur for DR, CVR, and the purchase of the Covert plant in the next three years are reasonable and prudent, should be approved for cost recovery purposes, and will be included in Consumers next electric rate case, consistent with Sections (11) and (17) of Act 341, MCL 460.6t(11),(17). *Id.*, p. 4. The parties agree to the projected capacity values provided by the Covert plant, and DR, CVR, and EWR resources in the next three years. *Id.*

The settlement provides for the approval of a battery deployment program as proposed in rebuttal testimony of company witness Blumenstock in the principal case. *Id.*; *see also*, 3 Tr 185, 203-205.

The settlement agreement provides that D.E. Karn (Karn) Units 3 and 4 will be retired on or before May 31, 2031, and J.H. Campbell (Campbell) Units 1, 2, and 3 will be retired on or before May 31, 2025. Settlement Agreement, pp. 4-5.

The settlement agreement provides that Consumers shall issue a one-time competitive solicitation following the approval of the settlement agreement that includes the following parameters:

a. The One-Time Solicitation will seek projects which will provide the Company with capacity credit in the MISO [Midcontinent Independent System Operator, Inc.] Zone 7 starting in the 2025 Planning Year;

b. The One-Time Solicitation will include two all source tranches:

i. The first tranche will seek up to 500 ZRCs [zonal resource credits] of capacity and associated energy and renewable energy credits (“RECs”), if applicable, from PPAs [power purchase agreements] with terms up to 10 years. This tranche will seek dispatchable, nonintermittent generation capable of dispatching up or down in every hour of the year in response to wholesale energy market signals, providing capacity which meets the Local Clearing Requirement of MISO Zone 7; and

ii. The second tranche will seek up to 200 ZRCs of capacity and associated energy and RECs, if applicable, secured from unaffiliated third parties via PPAs or other third-party agreements that do not result in Company ownership with terms up to 25 years, at the discretion of the bidder. This tranche will seek intermittent resources and dispatchable, nonintermittent clean capacity resources (including battery storage resources), providing capacity which meets the Local Clearing Requirement of MISO Zone 7. This tranche will furthermore take into consideration the ability of the offered capacity to meet the Local Clearing Requirement of MISO Zone 7 for the duration of the contract length. Prior to the issuance of the second tranche portion of the OneTime Solicitation, the Company shall hold a stakeholder meeting including parties to this case and energy storage developers to discuss methods to improve RFPs [requests for proposals] and response to solicitations with respect to stand-alone storage projects and hybrid-storage projects.

c. The Company’s acquisition of the 700 ZRCs and associated energy and RECs, if applicable, sought in the One-Time Solicitation shall be considered incorporated into the PCA approved in Paragraph 1 of this Settlement Agreement. However, the actual selected bid(s) will be submitted in Case No. U-21090 for Commission approval subsequent to the completion of the OneTime Solicitation;

i. In that approval proceeding, the Commission shall: (i) confirm whether the solicitation process followed by the Company is consistent with the requirements of the Settlement Agreement; (ii) grant approval of the recovery of the costs associated with the selected project(s) pursuant to applicable law or make a preliminary finding that the costs associated with the project(s) that

prevail in the solicitation are reasonable and prudent; and (iii) grant any other approvals or findings necessary as required or provided by applicable law.

d. The One-Time Solicitation will not be used to set the Company's avoided costs rates or capacity needs under PURPA.

Id., pp. 6-7.

The settlement agreement provides for an extension of the annual competitive bidding process used to acquire supply-side resource technologies as approved in the settlement agreement in Case No. U-20165 with modifications. *Id.*, pp. 7-9.

The settlement agreement provides that Consumers "will donate \$5 million in 2022 to a low-income fund that provides bill assistance to Consumers Energy's electric customers." *Id.*, p. 11. The settlement agreement also provides that Consumers will donate \$2 million annually to the same fund during the amortization period for the regulatory asset created to recover the unrecovered book balance of Campbell Units 1, 2, and 3. *Id.* These donations will not be recovered in rates. *Id.*, p. 12.

The settlement agreement provides that in future IRPs, Consumers will: "(i) collect the necessary data to compute marginal line losses and report these with average line losses and (ii) include marginal line losses and avoided transmission and distribution costs in its evaluation of all distributed resources, including residential DR potential." *Id.*

The settlement agreement provides that Consumers will "develop a distributed generation as a resource model approach that considers economic distribution connected solar to be modeled by bundling resources installed at the customer level to compare the total economic costs to the utility of distributed generation as a resource to other selectable supply-side resources" *Id.* The settlement also provides that in its next IRP, Consumers will "consider transmission and how it can facilitate the mitigation of reliability and economic impacts to the electric system." *Id.*, p. 13.

The settlement agreement provides that Consumers’ next IRP will include further analyses on environmental emissions, health impacts from emissions, and environmental justice. The settlement agreement also provides that Consumers will “take . . . steps to engage and gather input from the public prior to the filing of its next IRP with the Commission . . .” *Id.*, pp. 13-14.

IV. Evidentiary Record

Because the Commission has decided to read the record for purposes of evaluating the settlement agreement, a summary of the evidentiary record related to the settlement agreement follows.¹

A. Direct Testimony

1. Michigan Environmental Council, Natural Resources Defense Council, Inc., Sierra Club, and Citizens Utility Board of Michigan

MNS and CUB presented the direct testimony of Douglas B. Jester. Mr. Jester testifies that the settlement agreement is in the public interest and recommends that the Commission approve the settlement agreement. Mr. Jester opines that “retiring the entire Campbell plant will benefit both customers and the environment and is therefore in the public interest.” 10 Tr 4327.

Mr. Jester notes that no party in this case opposed the retirement of Campbell Units 1 and 2 and adds that the ALJ also recommended approval of these retirements. Mr. Jester posits that “[t]he Campbell plant has a greater carbon impact than any other resource owned by [Consumers], and its retirement is critical to meeting state and federal climate goals, including the Michigan Healthy Climate Plan.” 10 Tr 4327 (footnote omitted). Mr. Jester presents tables compiling Michigan’s greenhouse gas emissions and the associated goals from the MI Healthy Climate Plan to

¹ The Commission notes that, in the original IRP proceeding that resulted in a PFD, the evidentiary record included 4,094 pages of transcript across nine volumes and over 500 exhibits with certain transcript pages and exhibits designated as confidential. PFD, p. 3. The Commission references this evidence throughout this order.

demonstrate that it is “not possible to meet the 2025 goal of the Michigan Healthy Climate Plan without the retirement of the Campbell plant by 2025[,]” adding that, “the Michigan Healthy Climate Plan calls for the retirement of all coal generation by 2030, which would necessarily include the Campbell units.” 10 Tr 4330.

Mr. Jester adds that because the Campbell plant emits other pollutants, such as sulfur dioxide (SO₂), nitrogen oxide (NO_x), and particulate matter (PM_{2.5}), the retirement of the entire Campbell plant is likely to have health benefits beyond those of reducing the company’s carbon output. 10 Tr 4327.

In addition to the environmental and health benefits outlined above, Mr. Jester testifies that “[e]xtensive modeling conducted by Consumers and by MNS in this case demonstrated that retiring Campbell in 2025 is economic for customers.” 10 Tr 4327.

Mr. Jester provides that “paragraph 1 of the [settlement] agreement approves Consumers’ continued ramp-up of solar resources—an initiative first approved as part of Consumers’ 2018 IRP.” 10 Tr 4330. Additionally, Mr. Jester provides that:

In the 2018 case, the Commission approved a plan that included approximately 5 GW [gigawatts] nameplate [capacity] of new solar resources in the 2020s. In this case, Consumers proposed to continue those additions and also procure an additional 2 GW of solar in the 2030s above the levels included in the 2018 IRP. Paragraph 8 of the settlement agreement provides that Consumers will continue to utilize annual competitive solicitations to procure these solar resources.

10 Tr 4330. Mr. Jester posits that the Consumers’ proposed procurement is a reasonable and beneficial settlement term. 10 Tr 4330. Mr. Jester notes that the benefits the Commission recognized in 2018 IRP, such as the environmental benefits of additional renewable energy resources and the use of annual solicitations to promote competitive pricing, will continue with the new settlement agreement. 10 Tr 4331.

With respect to the proposed gas plant acquisitions, Mr. Jester opines that the settlement agreement terms regarding the acquisition of the Covert gas plant are reasonable and prudent. 10 Tr 4331. Mr. Jester provides that these terms include the approval of the acquisition of Covert and the recovery of the associated \$815 million purchase cost. The parties also agreed that Consumers would not obtain the CMS plants from its affiliate, CMS Enterprises Company (CMS Enterprises). 10 Tr 4331.

Mr. Jester notes that no party opposed the acquisition of the Covert plant and the ALJ recommended the Commission approve the acquisition. 10 Tr 4331. Mr. Jester posits that both the Staff and Consumers testified in the primary proceeding that “because Covert is currently in PJM [PJM Interconnection, L.L.C.’s American Electric Power (AEP) Zone], Consumers’ acquisition of Covert will add 1,114 Zonal Resource Credits or ZRCs to MISO Zone 7.” 10 Tr 4331. Mr. Jester adds that the addition of these ZRCs to Zone 7 “will support reliability for Consumers as well as overall resource adequacy for Zone 7.” 10 Tr 4331. Mr. Jester concludes that “[f]or these reasons, acquisition of Covert is both in the public interest from a reliability and resource adequacy standpoint” and is supported by the record in this case. 10 Tr 4331.

Mr. Jester asserts that Consumers’ agreement not to acquire the CMS plants is also in the public interest. Mr. Jester posits that the record demonstrated numerous concerns with acquisition of these plants from CMS Enterprises including, “issues with respect to affiliate transactions” and “the nature of the gas plant RFP solicitation that led to the proposed purchase of these plants” 10 Tr 4331-4332. Finally, Mr. Jester notes that the ALJ and the Staff also recommended the Commission deny the acquisition of the affiliate plants from CMS Enterprises. 10 Tr 4332.

Mr. Jester supports the proposed one-time solicitation of capacity and energy for the 2025 planning year (PY). Mr. Jester outlines the terms of the one-time solicitation as follows:

In paragraph 6 of the settlement [agreement], the parties agree that Consumers will issue a one-time competitive solicitation for PPAs to begin in PY 2025. The solicitation will contain two tranches. The first tranche will seek up to 500 ZRCs of energy and capacity for up to 10 years from dispatchable, non-intermittent generation. The second tranche will seek up to 200 ZRCs of energy and capacity for up to 25 years from clean energy resources (including battery storage).

10 Tr 4333. Mr. Jester posits that “[t]he first tranche will provide energy and capacity of similar characteristics to what Consumers sought via the proposal to acquire the CMS plants[,]” adding that “soliciting 10-year PPAs instead of acquiring affiliate assets planned to remain in rate base until 2040 will reduce risks to customers.” 10 Tr 4333. Mr. Jester also notes that a solicitation for PPAs addresses some of the issues identified with the earlier RFP by parties and the ALJ’s decision, which include that the earlier RFP only sought assets for purchase, and risks related to environmental permitting and fixed operating and maintenance expenses. 10 Tr 4333. Mr. Jester testifies that the second tranche is also in the public interest as it will “provide additional clean energy resources for Consumers’ portfolio” 10 Tr 4334.

Mr. Jester provides that “[p]aragraph 4(i) of the settlement [agreement] provides that Karn units 3-4 will not retire in 2023 but instead will continue operating and retire on or before their previously planned retirement date of May 31, 2031, absent extraordinary circumstances.”

10 Tr 4334. Mr. Jester posits that Karn Units 3 and 4 “provide substantial capacity but operate infrequently.” 10 Tr 4334. Mr. Jester testifies that “[c]ontinuing to operate Karn 3-4 supports Consumers’ attainment of planning reserve margin requirements [PRMR] by maintaining more than 780 ZRCs in the Company’s portfolio.” 10 Tr 4334. Further, Mr. Jester notes that Karn Units 3 and 4 staying online supports resource adequacy in MISO Zone 7 by maintaining these additional ZRCs. Mr. Jester testifies that keeping Karn Units 3 and 4 in operation removes the “unrecovered net book value from the total balance of the regulatory asset that Consumers seeks . . . lowering the costs of the regulatory asset for customers.” 10 Tr 4334-4335.

Mr. Jester supports the regulatory asset provisions of the settlement agreement mentioned above. Mr. Jester provides that “[i]n paragraph 5 of the settlement, the parties agree that after retirement of the Campbell plan in 2025, the return on equity used to calculate the WACC [weighted average cost of capital] for the regulatory asset will be 9.0%.” 10 Tr 4335. Mr. Jester posits that:

Consumers has taken a very firm position that it will not retire Campbell in 2025 without being able to recover a return of and on the unrecovered balance. Therefore, it was necessary for the other parties to agree with a regulatory asset based on WACC for this settlement [agreement] to occur and to facilitate Consumers’ permanent exit from coal generation three years from now.

10 Tr 4335. Mr. Jester notes, however, that “setting the ROE [return on equity] at 9.0% for the calculation of the WACC on the regulatory asset is a significant compromise for Consumers, as that figure is substantially lower than the authorized ROE of 9.9% that the Commission approved in Consumers Energy’s last electric rate case, [Case No.] U-20963.” 10 Tr 4335.

Mr. Jester posits that Consumers’ low-income customer bill assistance donations are a beneficial settlement term. Mr. Jester provides that “Consumers agreed in paragraph 13 of the settlement [agreement] to donate funds to its low-income bill assistance programs.” 10 Tr 4336. Mr. Jester notes that these funds will not be recovered in rates. Specifically, “Consumers will donate \$5 million in 2022 and \$2 million per year for the rest of the term of the regulatory asset for the Campbell plant.” 10 Tr 4336. Mr. Jester asserts that “[t]he need for additional low-income customer bill assistance has been demonstrated both in recent Consumers electric rate cases and in recent Consumers EWR cases, and recognized by the Commission in a variety of orders.” 10 Tr 4336 (footnote omitted).

Mr. Jester provides that “[p]aragraph 9 of the settlement [agreement] requires Consumers to use commercially reasonable efforts to maintain the 50/50 split between owned resources and

PPAs for new solar procurements” that was first approved in the settlement agreement in Case No. U-20165. 10 Tr 4336. Mr. Jester also notes that paragraph 9 “creates an absolute cap of 60% on capacity that Consumers acquires for ownership in any annual solicitation, while setting no cap on the amount of new solar the Company may acquire via PPA” and “maintains the bar on Consumers affiliates participating in the PPA portion of the solicitations.” 10 Tr 4337. Mr. Jester opines that “[t]he Commission found this allocation reasonable and in the public interest” in Consumers last IRP and that “this term maintains the essential components of that agreement.” 10 Tr 4337. Mr. Jester posits that making a commercially reasonable efforts to maintain the 50/50 split “promotes competition among third-party developers which reduces customer costs” and “helps support the solar industry in Michigan.” 10 Tr 4337. Mr. Jester notes that this provision of the settlement agreement is consistent with the ALJ’s recommendations on the issue. 10 Tr 4337.

Mr. Jester testifies that paragraph 10 of the settlement agreement provides for an extension of the FCM approved in Case No. U-21065, Consumers’ 2018 IRP. 10 Tr 4337. Mr. Jester opines that “[a]n FCM is a reasonable incentive for the Commission to authorize” given that “Consumers has substantially changed its business model by agreeing to shift its resource portfolio away from coal generation and toward solar generation, and by agreeing to procure the solar generation via competitive solicitations under which half of that capacity will be in the form of PPAs.” 10 Tr 4338.

Mr. Jester provides that paragraph 16 of the settlement agreement “states that the parties agree in Consumers’ next IRP to consider how transmission investments can improve reliability and access to economic sources of power from areas outside Zone 7.” 10 Tr 4338. Mr. Jester supports the transmission provision as a reasonable and beneficial settlement term and notes that the ALJ’s

decision “found that Consumers’ transmission analysis in this case was deficient and did not meet the terms of the settlement agreement in [Case No.] U-21065.” 10 Tr 4338-4339.

Mr. Jester supports the proposed battery storage investments outlined in the settlement agreement. Mr. Jester provides that the “parties agree to approval of a battery deployment program in paragraph 3 of the settlement agreement” as proposed in the principal rebuttal testimony in this case. 10 Tr 4339. Mr. Jester outlines that “Consumers proposed . . . to advance investment in 75 MW [megawatts] of battery storage resources. The settlement [agreement] reserves approval of the costs of the program to future electric rate cases.” 10 Tr 4339. Mr. Jester posits that Consumers made the battery proposal in response to testimony from the Staff, MNS, and other parties that “called for acceleration of battery storage investments as part of Consumers’ resource portfolio for this IRP.” 10 Tr 4339. Mr. Jester notes that “battery deployment will provide another clean energy resource to bolster Consumers’ maintenance of its PRMR and support resource adequacy in Zone 7.” 10 Tr 4339.

Mr. Jester provides that in paragraph 14 of the settlement agreement, Consumers agrees “to collect further data on marginal line losses and to include marginal line losses and avoided transmission and distribution (T&D) costs in the evaluation of all distributed resources, including residential demand response, for its next IRP.” 10 Tr 4340. Mr. Jester defers to testimony of CUB witness David Gard and MNS witness Chris Neme in explaining “the importance of these issues to the evaluation of EWR potential and DR potential for future IRPs.” 10 Tr 4340.

Mr. Jester notes that paragraphs 17 and 18 of the settlement agreement contain provisions regarding an environmental justice analysis and community outreach for Consumers’ next IRP. Mr. Jester supports these settlement terms and posits that “[t]he environmental justice analysis will provide vital information regarding the people and communities who bear disproportionate

impacts of electric generation activities—information that has been lacking in Michigan IRP cases up until now.” 10 Tr 4341.

Finally, Mr. Jester provides that “[p]aragraph 7 of the settlement agreement requires Consumers to publicly file its community transition plans for the Campbell and Karn sites.” 10 Tr 4341. Mr. Jester defers to testimony of MNS witness Tyler Comings regarding the need for public filing of transition plans. 10 Tr 4341.

Mr. Jester concludes that “[t]he settlement agreement in this case continues and significantly extends the progress of the settlement [agreement] in [Case No.] U-20165.” 10 Tr 4341. Mr. Jester posits that the settlement agreement is “supported by the great weight of evidence in the record of this case and consistent with many of the findings and recommendations in the PFD.” 10 Tr 4342. Thus, Mr. Jester recommends the Commission approve the proposed settlement agreement.

2. Environmental Law and Policy Center of the Midwest, Ecology Center, Inc., Union of Concerned Scientists, Inc., and Vote Solar

The CEOs presented the direct testimony of James Gignac, Senior Midwest Energy Analyst employed by the Union of Concerned Scientists. Mr. Gignac posits that the proposed settlement supports the public interest. Mr. Gignac posits that the settlement agreement “supports the public interest in three main ways: (1) it aligns with important climate action goals intended to protect Michiganders; (2) it improves economic and public health outcomes; and (3) it includes beneficial modeling and community engagement commitments for the Company’s next IRP.” 10 Tr 4375.

Mr. Gignac avers that “Consumers approach of retiring all its coal-fired power plants by 2025 aligns with Governor Whitmer’s MI Healthy Climate Plan’s goal to phase out Michigan’s remaining coal plants by 2030” and “the Company’s plans to add 8,000 megawatts of solar by

2040 is an important step toward the MI Healthy Climate Plan’s target for renewable energy to be providing 60 percent of Michigan’s electricity generation by 2030.” 10 Tr 4375.

Mr. Gignac posits that “the proposed settlement [agreement] helps reduce financial and public health costs related to Consumers’ resource plan” because “the Company has agreed to a lower rate of return for its retiring coal plants and will commit tens of millions of dollars of shareholder funds to support bill assistance for lower-income customers.” 10 Tr 4376. Mr. Gignac opines that expert testimony in this case “demonstrated the benefits of earlier coal plant retirements in the form of avoided negative health outcomes.” 10 Tr 4376.

Finally, Mr. Gignac argues that commitments made by Consumers for its future IRPs “will ensure that additional information and perspectives are available to inform both the Company’s assessment of its future resource options as well as Commission and stakeholder review of its proposals.” 10 Tr 4376-4377. Mr. Gignac includes the agreement to model distributed generation as a resource, to conduct public health and environmental justice analyses, and to expand opportunities and forums for community input among the beneficial modeling and community engagement commitments made by Consumers. 10 Tr 4376-4377.

For the reasons outlined above, Mr. Gignac concludes that the Commission should approve the settlement agreement as it “represents a reasonable resolution of the issues” 10 Tr 4377.

3. Energy Michigan

Energy Michigan presented the direct testimony of Alexander J. Zakem. Mr. Zakem testifies that in the contested settlement agreement, Consumers fails to address the impacts the PCA will have on resource adequacy and the competitive market. Mr. Zakem explains that the settlement agreement does not require that the 500 ZRC capacity need that Consumers is seeking to fill through the one-time solicitation agreed to under subsection 6.b.i of the settlement agreement “be

additional to what is already being counted toward MISO Zone 7's resource adequacy requirements." 10 Tr 4297. Mr. Zakem opines that because the settlement agreement does not require that the capacity being added by Consumers be additional to that already available in Zone 7, the settlement agreement is subject to concerns about "insufficient resources in the zone for a competitive pricing market." 10 Tr 4298. Mr. Zakem therefore recommends the Commission "examine the [s]ettlement [agreement] carefully and review its effects on resource adequacy and competitive pricing in Zone 7" and if the Commission finds that the settlement agreement "fails to adequately address resource adequacy or anti-competitive concerns, then the Commission should reject the [s]ettlement [agreement]." 10 Tr 4298.

4. The Commission Staff

In the Staff's direct testimony, Paul Proudfoot, the Director of the Energy Resources Division, asserts that Consumers' PCA, as modified by the settlement agreement, meets the statutory requirements of Section 6t(8) of Act 341, MCL 460.6t(8). 10 Tr 4400. For this reason, Mr. Proudfoot recommends the Commission approve the contested settlement agreement in its entirety without recommending changes under Section 6t(7). 10 Tr 4400. Mr. Proudfoot also states that the contested settlement agreement meets the requirements of Rule 431. 10 Tr 4400.

5. Biomass Merchant Plants

The BMPs presented the direct testimony of Richard A. Polich, a Managing Director with GDS Associates, Inc. Mr. Polich testifies that the continued operation of the biomass plants can offset some deficiencies he posits are present in the proposed contested settlement agreement.

Mr. Polich opines that the settlement inconsistently results in Consumers having excess generation capacity in some years and capacity shortages in other years, which he argues is contrary to IRP best practices. Mr. Polich explains:

The settlement [agreement] includes procurement of the Covert Generation Facility (Covert) in 2023 which results in Consumers' having 20.1% excess capacity. It then adds 700 MW (ZRC) of generation resources in 2025 that is procured through a competitive solicitation that is deeply flawed. Although Consumers retires 1,344 MW (ZRC) of generation in 2025, the [s]ettlement [agreement] would result in 16.2% excess generation in 2025 and an average of 18.7% excess generation over the next six years, assuming solar generation continues to be accredited at 50% of real capacity by MISO.

10 Tr 4277. Further, Mr. Polich adds that “[t]he addition of Covert in 2023 means Consumers’ rate payers will be paying 2 years of unnecessary costs for Covert capacity that is unnecessary.”

10 Tr 4277. Mr. Polich likens the biomass plants to solar generation as they are net zero carbon generation and to natural gas plants as they are baseload generation. Mr. Polich concludes that:

If it is reasonable and prudent for Consumers to acquire both fossil and renewable capacity from 2023 through 2030 that results in excess capacity for the period of 2023-2030, the prudent course of action is for Consumers to continue to purchase capacity and energy from the Biomass Plants after the expiration of their current contracts through at least 2035 when Consumers is likely to be capacity deficient.

10 Tr 4278.

Mr. Polich argues that the one-time solicitation outlined in section 6 of the settlement agreement is “deeply flawed.” 10 Tr 4278. Mr. Polich posits that the timing of the competitive solicitation is flawed as “Consumers is proposing to start the procurement process so the capacity of both tranches will provide capacity in 2025.” 10 Tr 4278. Mr. Polich opines that:

The timing of the procurement process will not result in new capacity being added to the Michigan market and will likely favor existing generation facilities such as the Kalamazoo Plant, Livingston Plant and Dearborn Industrial Generation because it will be impossible for new generation to obtain a MISO Interconnection Services Agreement, complete project engineering, obtain financing and construct the plant by 2025.

10 Tr 4279. Mr. Polich concludes that, given the timeline to obtain a MISO interconnection agreement, complete project engineering, and obtain financing, “it is very unlikely that there will be sufficient time to complete a power generation project for operation in 2025.” 10 Tr 4279.

Mr. Polich also argues that “MISO Zone 7 is projected to be short 397.4 MW (ZRC) in 2023.” 10 Tr 4279. Mr. Polich notes that “MISO’s recent [sic] completed 2022/2023 Planning Resource Auction (PRA) resulted in capacity shortages in all northern MISO regions due to planned retirements of fossil generation resources The PRA resulted in capacity costs of \$236.66/MW-day in MISO Zone 7, which is equal to the cost of new entry [CONE] or cost of adding new gas fired generation.” 10 Tr 4279. Mr. Polich posits that this “shows the volatility of the MISO planning process to which Consumers and its customers will be subject.” 10 Tr 4279.

Mr. Polich posits that the one-time solicitation outlined in the settlement agreement “results in a preference for non-intermittent fossil generation . . .” 10 Tr 4280. As outlined in the settlement agreement, the one-time solicitation seeks projects that will provide the company with capacity in MISO Zone 7 starting in the 2025 planning year. The settlement agreement also states that the first tranche will seek “dispatchable, non-intermittent generation capable of dispatching up or down in every hour of the year in response to wholesale energy market signals, providing capacity which meets the Local Clearing Requirement of MISO Zone 7.” Settlement Agreement, p. 6. Mr. Polich argues that these requirements preclude the participation of the BMPs as they will still be under contract in 2025 and can be dispatched on 24 hours-notice, as opposed to hourly. 10 Tr 4280. Mr. Polich further asserts that “only generation resources which are currently operating, not under contract with Consumers, have obtained MISO interconnection approval, and completed primary engineering are likely to be able to bid into the One-Time Solicitation.” 10 Tr 4280.

Mr. Polich takes issue with the language in the settlement agreement describing the second tranche of the one-time solicitation that states, “[t]his tranche will seek intermittent resources and dispatchable, nonintermittent clean capacity resources.” 10 Tr 4280 (quoting Settlement

Agreement, p. 6). Mr. Polich posits that “[t]he term ‘clean capacity resources’ is an undefined term and can mean any generation resource that is cleaner than [sic] Consumers existing generation resources. Thus, natural gas plants could offer proposals into the second tranche because the language is very ambiguous.” 10 Tr 4280.

Mr. Polich opines that “the One-Time Solicitation will likely result in Consumers acquiring [a] substantial amount of natural gas capacity in addition to the Covert capacity.” 10 Tr 4281. Mr. Polich argues that an increase in the average price of natural gas over the last two years “clearly demonstrates the volatility of natural gas pricing and highlights the risk of becoming totally dependent on such a single, volatile fuel source.” 10 Tr 4281.

Mr. Polich also posits that the one-time solicitation in the second tranche of the settlement agreement “will likely result in the acquisition of only intermittent generation because solar generation with battery storage will likely be too expensive to compete with solar generation without battery storage and due to shortages of materials[,]” specifically lithium carbonate. 10 Tr 4281.

Mr. Polich opines that if MISO changes the solar ZRC accreditation from its current 50% accreditation to a 30% accreditation, Consumers will face a capacity shortfall in 2031 due to closing of Karn Units 3 and 4 and the expiration of Consumers contract with Midland Cogeneration Venture. 10 Tr 4282.

Mr. Polich avers that the settlement agreement does not meet the stated goals of paragraph 16 “to be Carbon Neutral by 2040[,]” as the Covert plant and 200 MW of generation from PPAs originating under the one-time solicitation “are fossil fuel generation resources and are not carbon neutral.” 10 Tr 4283.

In conclusion, Mr. Polich requests, on behalf of the BMPs that “the Commission approve the Settlement Agreement only if it is amended to include a provision whereby Consumers Energy continues to purchase capacity and energy from the Biomass Plants” through amended PPAs. 10 Tr 4286.

6. Wolverine Power Supply Cooperative

WPSC presented the direct testimony of Thomas King, Jr. Mr. King argues that “Consumers Energy’s and Michigan’s reliability and resource adequacy situation is no better (and arguably, worse) under the proposed Settlement Agreement than in the originally filed IRP.” 10 Tr 4301. Mr. King posits that “the changes reflected in the proposed Settlement Agreement continue to assume capacity replacements that add no incremental capacity to MISO Zone 7.” 10 Tr 4302. Mr. King provides MISO’s 2022 PRA results as exhibit WPSC-6. Mr. King argues that this exhibit demonstrates why MISO’s North and Central Zones cleared at CONE in 2022. Mr. King quotes MISO as stating “that previous projections of surplus were ‘eroded by an increased load forecast, less capacity entering the auction as result of retirements, and the decreased accredited capacity of new resources.’” 10 Tr 4303 (quoting Exhibit WPSC-6, slide 2)(emphasis omitted). Mr. King posits that “[w]hen load growth is under-forecasted, dispatchable resources are retired too quickly, and intermittent resources are over-accredited, reliability is at risk.” 10 Tr 4303. Mr. King further quotes the MISO 2022 PRA results as stating that “[u]nless more capacity is built that can supply reliable generation, shortfalls such as those highlighted in this year’s auction will continue.” 10 Tr 4303 (quoting Exhibit WPSC-6, slide 9).

Mr. King further avers that under the settlement agreement, Consumers’ plan is “based almost entirely on a 700 MW speculative solicitation of both dispatchable and intermittent resources that

likely cannot be built in time and, therefore, is likely to result in the purchase from the affiliated plants because they will be the only dispatchable resources in Zone 7” 10 Tr 4302-4303.

Finally, Mr. King argues that “when Consumers’ PCA and proposed Settlement Agreement assumptions are updated to reflect more current data from Consumers’ own capacity demonstration filing in Case No. U-21099 and more reasonable assumptions, Consumers will likely be capacity negative in 2025[,]” meaning it will be “unlikely to serve its own load with its own resources in 2025.” 10 Tr 4303-4304. Mr. King posits that the assumptions Consumers used in its capacity demonstration are unreasonable. Specifically, Mr. King states that it is unreasonable for Consumers to assume a declining PRMR in its PCA and capacity demonstration as “it conflicts with MISO’s statements of increasing load forecasts (see Exhibit WPSC-6), Wolverine’s own growth, and publicly disclosed growth in Michigan.” 10 Tr 4305. Similar to the BMPs, Mr. King avers that “MISO is considering changes to solar capacity accreditation to move from a static solar accreditation value to an Effective Load Carrying Capability (ELCC) approach, similar to what is used for wind.” 10 Tr 4306-4307. Mr. King also outlines similar concerns regarding supply chain challenges causing disruptions to solar project developments. Specifically, Mr. King opines that “disruptions in the solar industry due to the United States Department of Commerce [DOC] investigation into Chinese solar tariff avoidance, are likely to result in project development delays.” 10 Tr 4307.

Mr. King concludes that the Commission “should reject this settlement [agreement]” and “adjust the timeline for retirement of Campbell 3 in a way that reasonably ensures replacement is possible—not only for the joint owners of Campbell 3, but for all LSEs [load serving entities] who rely on the grid to ensure their own reliability” 10 Tr 4309.

B. Rebuttal Testimony

1. Michigan Environmental Council, Natural Resources Defense Council, Inc., Sierra Club, and Citizens Utility Board of Michigan

Mr. Jester, on behalf of MNS and CUB, responds to the direct settlement testimony of WPSC, Energy Michigan, and the BMPs. Mr. Jester focused his rebuttal testimony on “the objecting parties’ claims regarding resource adequacy, the procurement of new clean energy resources by 2025, and MISO capacity credit for solar resources.” 10 Tr 4346.

Mr. Jester responds to claims by WPSC and Energy Michigan that the settlement agreement would worsen the resource adequacy measures in Zone 7 by arguing that “[u]nder the settlement, more than 2,000 ZRCs of capacity will be added to Zone 7 over the next several years.”

10 Tr 4349. Mr. Jester posits that “[t]hese resource additions will not only provide replacement capacity for the retiring Campbell coal plant in 2025, they will result in a significant net increase of capacity when compared to the status quo.” 10 Tr 4349. Specifically, Mr. Jester provides that “the settlement [agreement] will add 1,114 ZRCs to MISO Zone 7 through the acquisition of the Covert combined-cycle gas plant in 2023.” 10 Tr 4349 (footnote omitted). Mr. Jester adds that “the settlement [agreement] provides that Consumers will deploy a new, utility-scale battery storage program in the years 2024-27, which will add approximately 71 ZRCs of new capacity.” 10 Tr 4349-4350 (footnote omitted). Mr. Jester posits that “because the settlement agreement preserves the solar ramp-up proposed as part of the original PCA, the settlement [agreement] would add 250 ZRCs of new solar generation by the 2025/2026 planning year, increasing to 852 ZRCs by 2028/2029 with further increases throughout the 2030s.” 10 Tr 4350 (footnote omitted). Finally, Mr. Jester argues that “by preserving the EWR and DR provisions from Consumers’ original PCA, the settlement [agreement] will provide 94 ZRCs of demand-side resources by 2025/26, increasing to 231 ZRCs by 2028/29, with further increases in later years.”

10 Tr 4350 (footnote omitted). Mr. Jester concludes that these resource additions will support resource adequacy by providing replacement capacity for the retiring Campbell Units in May 2025. Specifically, Mr. Jester avers that “[i]n the 2025/2026 planning year . . . the settlement [agreement] will result in a projected net increase of at least 127 ZRCs. By 2028/29, the projected increase will be at least 923 ZRCs.” 10 Tr 4350. Mr. Jester notes that these calculations are conservative as they only account for the first tranche of the one-time solicitation seeking up 500 ZRCs of energy and capacity for up to 10 years from dispatchable generation and do not include the resources from the second tranche seeking up to 200 ZRCs of energy and capacity for up to 25 years from clean capacity resources. Mr. Jester posits that the calculations also assume that all of the dispatchable ZRCs come from existing generation sources. Mr. Jester concludes that “the settlement [agreement] will bolster Zone 7’s resource adequacy” and as such, the Commission should disregard resource adequacy concerns raised by WPSC and Energy Michigan. 10 Tr 4352.

Mr. Jester responds to claims by WPSC and posits that “the settlement agreement will improve Consumers’ capacity position relative to the original IRP.” 10 Tr 4352. Mr. Jester opines that WPSC’s claim that the proposed settlement agreement continues to assume capacity replacements that add no incremental capacity to Zone 7 is “plainly incorrect” as “the settlement provides for more than 2,000 ZRCs of new Zone 7 capacity over the next six years, including the addition of the Covert plant (1,114 ZRC) in 2023. 10 Tr 4353. Mr. Jester posits that, as explained above, the one-time solicitation will result in a net increase of ZRCs in both the 2025/26 and 2028/29 planning years. 10 Tr 4353.

Mr. Jester responds to WPSC’s arguments that solicited resources cannot be built in time to provide energy and capacity in the 2025/26 planning year. Mr. Jester posits that “no party has claimed that the dispatchable generation tranche will be supplied with new resources” and thus,

“the evidence does not support Mr. King’s speculative claims about the difficulty of developing new clean energy resources by 2025/26.” 10 Tr 4353. Further, Mr. Jester avers that “Consumers would have enough capacity resources to meet customer needs in 2025/26 even if the one-time solicitation failed entirely.” 10 Tr 4353.

Finally, regarding Consumers’ capacity position, Mr. Jester rebuts WPSC’s claim that Consumers will be capacity negative in 2025. Mr. Jester posits that the testimony provided by Mr. King “does not explain some of the assumptions reflected in [Exhibit WPSC-7]” and “does not present independent sources to support his claims about increased load and the PRMR margin.” 10 Tr 4355 (footnote omitted). Mr. Jester also avers that Mr. King’s projected capacity position assumes that Karn Units 3 and 4 were operating in planning year 2025/2026 when Consumers capacity demonstration filing assumed Karn Units 3 and 4 would have retired in 2023, and the CMS plants would be acquired in 2025, in line with the implementation of the original PCA. Mr. Jester notes that in Case No. U-21099, the Staff concluded that “all Michigan LSEs have satisfied the capacity demonstration requirements and have procured appropriate levels of resources for planning year 2025/26.” 10 Tr 4356 (quoting Case No. U-21099, filing #U-21099-0060, p. iii).

Mr. Jester addresses the arguments of the BMPs and WPSC about recent PRA results. As Mr. Jester summarizes, “Mr. Polich asserts that MISO Zone 7 is projected to be short in 2023, and Mr. King cites the PRA results in warning more broadly about reliability risks.” 10 Tr 4358 (footnote omitted). Mr. Jester opines that “[a]lthough . . . MISO should carefully scrutinize the PRA results and pursue solutions to improve resource adequacy for MISO North/Central, the auction results do not undercut the settlement agreement in this case.” 10 Tr 4358. Mr. Jester reiterates that “the settlement agreement will *improve* Zone 7’s resource adequacy.” 10 Tr 4358-

4359 (emphasis in original). Further, Mr. Jester posits that “[b]ecause the settlement improves the capacity position of MISO Zone 7, it therefore also improves the capacity position of MISO’s North/Central region.” 10 Tr 4360.

Mr. Jester responds to the BMPs’ and WPSC’s concerns that there is not enough time to develop new resources capable of bidding into the one-time solicitation for clean energy resources and the possible decline of the ELCC of solar. Mr. Jester posits that concerns about developing clean energy resources by the 2025/2026 planning year are based on the assumption that the development process would not start until 2023. 10 Tr 4361. Mr. Jester first reiterates his position that “no one has suggested that the dispatchable generation tranche (500 ZRCs) of the one-time solicitation will be filled with new resources. . . .” 10 Tr 4362. Mr. Jester then opines that while the witnesses for the BMPs and WPSC assume that projects will not begin development until 2023, “[i]n reality, there are numerous clean energy projects already in the MISO generator interconnection queue. Because these projects are already in development, many of them will likely be capable of bidding into the solicitations for planning year 2025/26.” 10 Tr 4362-4363. Mr. Jester posits that there are currently “more than 13,011 MW of solar, battery, and solar/battery hybrid projects located in the MISO Zone 7 that have an application in-service date by or before June 1, 2025” including “9,842 MW of solar, 1,249 MW of solar/battery hybrid, and 1,920 MW of battery storage.” 10 Tr 4363-4364 (footnotes omitted). Mr. Jester notes that a number of the projects have completed phase 2 or phase 3 of interconnection studies and are therefore highly likely to proceed. 10 Tr 4364. Mr. Jester thus concludes that the concerns raised by the BMPs and WPSC are misplaced.

Regarding the concerns of the BMPs and WPSC about the potential decline of solar ELCC from 50%, Mr. Jester posits that “[a]lthough MISO has had discussions about adjusting solar’s

ELCC as part of its future shift to a seasonal capacity market, no such proposal has been finalized nor submitted for FERC [Federal Energy Regulatory Commission] approval.” 10 Tr 4365.

Mr. Jester notes that a MISO stakeholder process subcommittee has been using modeling assumptions including an “ELCC of 50% through 2026, and with the ELCC linearly declining in subsequent years until it hits 20% in 2041.” 10 Tr 4365-4366 (footnote omitted). In his footnote, Mr. Jester elaborates that “[f]or the previous year’s analysis, the subcommittee modeled a decline to 30%, which may be where Mr. Polich got his figure.” 10 Tr 4366, n. 51. However, Mr. Jester opines that “[t]his modeling document does not undercut the reasonableness of the settlement agreement[,]” providing that “this document is simply describing a modeling analysis; it does not reflect a policy change.” 10 Tr 4366. Mr. Jester also provides that “accreditation for each solar facility begins at 50% until operational records from that facility become available, after which it is based on average production during the hours of 2pm to 5pm ET in the months of June, July, and August.” 10 Tr 4366 (footnote omitted). Mr. Jester argues that this distinction is important as “there is on-the-ground evidence in Michigan that the ELCC for solar facilities may be much higher.” 10 Tr 4367. Specifically, “Consumers currently has three solar facilities whose MISO capacity credit ranges between 56.67% and 67%.” 10 Tr 4367 (footnote omitted). Finally, Mr. Jester notes that “although the ELCC of new solar may decline if solar achieves high levels of penetration in Michigan, that effect can be mitigated, and this dynamic will not affect the capacity provided by solar deployed in the earlier years of Consumers’ resource plan.” 10 Tr 4367.

2. Environmental Law and Policy Center of the Midwest, Ecology Center, Inc., Union of Concerned Scientists, Inc., and Vote Solar

Kevin Lucas, Senior Director of Utility Regulation and Policy at the Solar Energy Industries Association (SEIA), responds to the direct settlement testimony of WPSC on behalf of the CEOs. Mr. Lucas responds to the assertion by WPSC’s witness, Mr. King, that the solar capacity sought

by Consumers “will not be available by 2025 due to the current United States Department of Commerce . . . investigation regarding avoidance of tariffs from Chinese-made solar cells.”

10 Tr 4382. Mr. Lucas provides that “the DOC is investigating whether solar imports from Cambodia, Malaysia, Thailand, and Vietnam are circumventing antidumping and countervailing duties on Chinese-made crystalline silicon cells” and further, “[i]f imposed, tariffs would increase the cost of solar products from these countries 50-250%” 10 Tr 4382. Mr. Lucas avers that “[b]ecause of the uncertainty surrounding pricing of solar panels due to the retroactive nature of potential tariffs, panel shipments to the US have largely frozen since DOC initiated its investigation. This in turn impacts projects that are under construction and planned to come online in the near future as they are unable to secure a supply of solar panels.” 10 Tr 4383. However, Mr. Lucas posits that “SEIA believes the current supply chain issue is largely short-term and that it will be mitigated when a decision is reached and as domestic manufacturing capacity comes online.” 10 Tr 4384. Thus, Mr. Lucas concludes that Mr. King’s arguments are not supported by analysis and “[w]hile there may be some projects in Michigan that experience schedule impacts from the DOC investigation, these impacts are concentrated in the relatively near-term period.” 10 Tr 4384.

3. The Commission Staff

Mr. Proudfoot, on behalf of the Staff, responds to the direct settlement testimony of Energy Michigan and WPSC. Mr. Proudfoot limits his rebuttal testimony to the issues of the resource acquisition methodology of the one-time solicitation, resource adequacy, and the application of the settlement agreement factors outlined in Rule 431(5) parts (b) and (c). Addressing Mr. Zakem’s concerns that the settlement agreement does not require that the 500 ZRCs acquired through the one-time solicitation be additional resources to those present in Zone 7, Mr. Proudfoot posits that

“Mr. Zakem fails to recognize that Subsection 6.b.1. does not require the 500 ZRCs to be pre-existing (already counted towards MISO Zone 7 resource adequacy).” 10 Tr 4404. Mr. Proudfoot notes that under the terms of the settlement agreement, these resources will be competitively bid, thus “respondents to the solicitation could be from some of the projects currently in the MISO Queue (ITC Transmission, Michigan only) that makes up nearly 1,800 MW of projects that are currently in Study Phase 2 or 3.” 10 Tr 4404 (footnote omitted).

Mr. Proudfoot states that, in contrast to the RFP conducted by the company in its IRP filing which was limited to pre-existing gas resources within Zone 7, “the Company is now requesting dispatchable, non-intermittent resources (not specifically gas) with no requirement to be pre-existing.” 10 Tr 4404. Mr. Proudfoot argues that “between existing projects and the intermittent and dispatchable projects in the MISO Queue, there is opportunity to add new capacity within MISO Zone 7.” 10 Tr 4404. Mr. Proudfoot also notes that in the second tranche of the one-time solicitation provided for in subsection 6.b.1.ii of the settlement agreement, “the Company will request 200 ZRCs from unaffiliated third parties via Power Purchase Agreements (PPAs) for intermittent and dispatchable resources.” 10 Tr 4405. Thus, Mr. Proudfoot concludes that “[b]etween the two tranches, the Settlement Agreement provides the opportunity for a wide variety of new resources to bid in and ultimately be built within MISO Zone 7” 10 Tr 4405.

Mr. Proudfoot responds to resource adequacy concerns made by Energy Michigan and WPSC. Mr. Proudfoot asserts that the settlement agreement is “a resource adequacy improvement over the Company’s original PCA.” 10 Tr 4405. Mr. Proudfoot cites the key difference between the resource adequacy of the company’s original PCA and the settlement agreement to be the delayed retirement of Karn Units 3 and 4. Mr. Proudfoot explains that the original PCA called for the retirement of Karn Units 3 and 4 by May 31, 2023, while the settlement agreement delays the

retirement until May 31, 2031. Mr. Proudfoot posits that Consumers “was originally proposing to retire approximately 2800 MW (nameplate) generation from MISO Zone 7” while the settlement agreement “only retires a portion of that amount, approximately 1500 MW” 10 Tr 4405. Further, Mr. Proudfoot notes that along with the commitment to retire the entire Campbell plant, Consumers “is proposing to add approximately 1176 MW to Zone 7 through the acquisition of the Covert Power Plant.” 10 Tr 4405. Further, Mr. Proudfoot provides that Consumers “continues its solar build out and is expected to add 300 MW of solar resources in 2023, 500 MW of solar resources in 2024, and 500 MW of solar resources in 2025[,]” noting that under the current MISO ELCC construct, “that is approximately 400 ZRC’s [sic] of new resources within MISO Zone 7.” 10 Tr 4406 (footnote omitted). Mr. Proudfoot adds that the one-time solicitation for 700 MW set forth in the settlement agreement is additional to the resources outlined above. 10 Tr 4406. Mr. Proudfoot concludes that the “Staff does not believe the [settlement agreement] is likely to result in the Company being short on capacity in 2025.” 10 Tr 4406. Mr. Proudfoot opines that the 7.4% reserve margin used by Consumers in its Capacity Demonstration in Case No. U-21099 is reasonable as it “comes directly from the 2022-2023 MISO Loss of Load Expectation (LOLE) Study Report.” 10 Tr 4406 (footnote omitted).

Regarding Rule 431(5)(a), Mr. Proudfoot testifies that all parties have been given an opportunity to present arguments in opposition to the settlement agreement through direct and rebuttal testimony. 10 Tr 4407. In regard to Rule 431(5)(b) and (c), Mr. Proudfoot asserts that the “Staff believes that Consumers has adequately met its requirements under [Public Act] 341 of 2016 . . . and provided a reasonable revised PCA.” 10 Tr 4407. Mr. Proudfoot posits that not only did Consumers and the Staff sign the settlement agreement, but so did other parties who represent residential customers (the Attorney General, CUB, and Urban Core Collective); commercial and

industrial customers (HSC, MCV, and MPPA); businesses in Michigan’s advanced energy sector (EIBC/IEI/CGA); environmental groups (MNS and the CEOs); a transmission company (METC); and third-party developers (GLREA). 10 Tr 4407-4408. Mr. Proudfoot opines that the signatories to the settlement agreement “represent most, if not all, of Michigan’s sectors concerned with the future of energy related issues.” 10 Tr 4408. Mr. Proudfoot concludes that “it is Staff’s opinion that this [settlement agreement] meets the requirements of Rule 431.” 10 Tr 4408.

4. Biomass Merchant Plants

Mr. Polich, on behalf of the BMPs, filed rebuttal testimony to reassert his position that the continued operation of the biomass plants fosters resource adequacy and contributes to Consumers goal of being carbon neutral by 2040. 10 Tr 4289. Mr. Polich takes the position that “it is in the Public Interest for the continued utilization of the Biomass Plants to be incorporated into the [s]ettlement [agreement] by extending their contracts through at least 2035” as it will “help alleviate Consumers’ capacity deficiency that occurs in several years of 2025 through 2038” 10 Tr 4289. Mr. Polich poses that there are “significant risks associated with adding 7,800 MW of solar capacity as proposed[,]” including the magnitude of the capacity; the possible lowering of MISO’s current 50% solar accreditation; and MISO interconnection, development, financing, and construction risks. 10 Tr 4290-4291. Mr. Polich also notes the settlement agreement’s “reliance on natural gas generation as the only form of non-intermittent generation to supplement the renewable generation.” 10 Tr 4291.

Mr. Polich responds to MNS’ position that the settlement agreement improves upon Consumers’ initially filed PCA by eliminating the purchase of certain gas plants from Consumers’ affiliate CMS Enterprises. Mr. Polich asserts that “[s]ince the only bidders in the One-Time Solicitation first tranche will likely be existing generation, the bidders will be the same entities that

bid into Consumers' solicitation that resulted in three CMS plants being successful bidders."

10 Tr 4292. Mr. Polich also responds to Mr. Jester's testimony that the second tranche of the one-time solicitation is beneficial to the public interest. Mr. Polich argues that "the timing of the solicitation and 2025 in-service date will limit bidders to those with MISO interconnection agreements, preliminary engineering, major equipment under contract, and rights to construction sites already procured" adding that "it is highly unlikely any generation project can be constructed by the summer of 2025 in-service date." 10 Tr 4293.

5. Wolverine Power Supply Cooperative

Mr. King, on behalf of WPSC, responds to the direct testimony of MNS and the BMPs. Mr. King focuses his testimony on Mr. Jester's claims regarding "the clear reliability deficiencies resulting from the proposed: (1) one-time solicitation; (2) retirement dates for Campbell Unit 3 and Karn Units 3 and 4; and (3) transmission considerations." 10 Tr 4311. Additionally, Mr. King focuses on Mr. Polich's "statements identifying Zone 7 and Consumers as import dependent." 10 Tr 4311.

Mr. King disagrees with Mr. Jester's position that "the one-time solicitation of 700 ZRCs contemplated in the disputed [settlement] agreement is a reasonable and beneficial settlement [agreement] term sufficient to replace the retirement of Campbell Unit 3." 10 Tr 4311. Mr. King reasserts that "500 of the 700 ZRC[s] are unlikely to result in any new capacity to Zone 7 due to the solicitation requirements being 'dispatchable, non-intermittent generation capable of dispatching up or down in every hour of the year...[in] Zone 7.'" 10 Tr 4312 (quoting Settlement Agreement, p. 6). Mr. King further provides that "only the CMS plants, or a portion thereof, are available today in Zone 7. And nothing new exists in MISO's interconnection queue." 10 Tr 4312. Mr. King posits that, "the second tranche of 200 ZRCs are likely to be procured from

intermittent resources . . . because much like Tranche 1, there are unlikely any nonintermittent resources available today or in the MISO interconnection queue.” 10 Tr 4312. Mr. King asserts that there are reliability implications if the CMS plants are the only resources available to participate in the one-time solicitation. Specifically, “[r]eplacing Campbell Unit 3 with existing Zone 7 capacity produces a net negative capacity position in the Zone.” 10 Tr 4312.

Mr. King opines that by supporting the retirement of Campbell Unit 3, Mr. Jester, “fails to analyze, or even consider, the public health and safety impacts resulting from lower reliability.” 10 Tr 4313.

Mr. King addresses Mr. Jester’s position that delaying the retirement of Karn Units 3 and 4 from 2023 to 2031 is a reasonable and beneficial settlement term. Mr. King argues that “[w]hile the continued operation of existing resources is prudent in order to maintain reliability, extending the retirement date for Karn Units 3 and 4 does not appear to be a reasonable or prudent path as the units are, [sic] less reliable and provide insufficient additional capacity.” 10 Tr 4314.

Specifically, Mr. King provides that the settlement agreement proposes to extend the operation Karn Units 3 and 4 which have an installed capacity of 1,120 MW and accredited capacity of 790 MW (70.5% accredited) while continuing to expedite the retirement of the Campbell Units which have an installed capacity of 1,393 MW and an accredited capacity of 1,346 MW (96.6% accredited). 10 Tr 4314.

Mr. King refutes Mr. Jester’s testimony supporting the settlement terms that require Consumers to consider the reliability and economic value of transmission in its next IRP to access resources outside Zone 7. Mr. King posits that this consideration must happen sooner than Consumers’ next IRP as “Zone 7 is already import reliant in the upcoming 2022/23 Planning Year (and has been for seven of the last nine capacity auctions) to meet its PRMR” 10 Tr 4314.

Mr. King avers that “[w]hen Consumers and Zone 7 are import reliant . . . [i]f one of a few existing ties fails or export capability (elsewhere) is reduced (e.g., retirements or forced outage), proportional load shed is the next step.” 10 Tr 4315.

Finally, Mr. King encourages improving access to external resources. 10 Tr 4315. Mr. King posits that “Michigan should demand greater, more resilient, and more diverse ties to the greater market/grid.” 10 Tr 4315.

6. Michigan Energy Innovation Business Council, Institute for Energy Innovation, and Clean Grid Alliance

EIBC/IEI/CGA presented the rebuttal testimony of Edward Burgess, the Senior Director at Strategen Consulting. Mr. Burgess responds to the direct testimony of Mr. Polich on behalf of the BMPs on “timing delays and other risks associated with solar development[,]” specifically, that the settlement “simply ignores risks associated with intermittent solar generation.”

10 Tr 4388-4389 (footnote omitted). Mr. Burgess opines that the settlement addresses some of these potential risks by turning them into opportunities, such as better utilization of Michigan manufactured components and low-carbon manufacturing. 10 Tr 4389. Mr. Burgess rebuts Mr. Polich’s position that the one-time solicitation outlined in the settlement agreement is flawed. Mr. Burgess posits that Mr. Polich’s assumptions that “the second tranche procurement Settlement Paragraph 6.b.ii ‘will likely result in the acquisition of only intermittent generation because solar generation with battery storage will likely be too expensive to compete with solar generation without battery storage and due to shortages of material’” is an improper reading of the settlement [agreement]. 10 Tr 4389-4390 (quoting 10 Tr 4281) (footnote omitted). Mr. Burgess asserts that “[t]he fact that the ‘duration of the contract length’ will be taken into account for all new supply side resources, including solar and battery storage capacity options, will enable especially battery storage capacity options to be evaluated on par with intermittent resources in terms of the full price

of the contract.” 10 Tr 4390 (quoting Settlement Agreement, p. 6). Further, Mr. Burgess adds that “the fact that the solicitation is tailored towards ZRCs that meet the Local Clearing Requirements of MISO Zone 7 means that it already inherently accounts for any intermittency concerns through the MISO capacity accreditation process.” 10 Tr 4390.

Finally, Mr. Burgess posits that the technology neutral language of the one-time solicitation in section 6.b.ii of the settlement agreement rectifies concerns that Consumers’ initial PCA “did not adequately model nor otherwise address the potential inclusion of battery storage resources.” 10 Tr 4391.

7. Consumers

Consumers presented the rebuttal testimony and exhibits of Richard T. Blumenstock, Thomas P. Clark, and Michael A. Torrey. Each witness’ testimony will be addressed here in turn.

Mr. Blumenstock, Executive Director of Electric Supply at Consumers, focuses his rebuttal testimony on responding to assertions raised by Energy Michigan, WPSC, and the BMPs.

Mr. Blumenstock provides an overview of how the settlement agreement aligns with subsection 6t(8)(a)(i-vii) of Act 341, MCL 460.6t(8)(a)(i-vii), on pages 7-15 of his rebuttal testimony.

Mr. Blumenstock responds to the testimony of Energy Michigan’s witness Zakem by claiming:

Energy Michigan is continuing to rely on its direct testimony as previously submitted in this case before the Settlement Agreement was reached The problem with that approach is that Mr. Zakem’s direct testimony was focused on the Company’s purchase of the Dearborn Industrial Generation (“DIG”), the Kalamazoo River Generating Station (“Kalamazoo”), and the Livingston Generating Station (“Livingston”) plants . . . and the Settlement Agreement no longer provides for the purchase of those plants in the manner initially proposed by the Company. Mr. Zakem has also made no adjustment to his initial position to account for the fact that the Settlement Agreement continues operation of Karn Units 3 and 4 until 2031, as opposed to 2023, as initially proposed by the Company.

10 Tr 4128-4129. Thus, Mr. Blumenstock posits that Mr. Zakem’s assessment “no longer accurately describes the elements of the PCA, as modified by the Settlement Agreement.”

10 Tr 4129. Mr. Blumenstock also claims that Mr. Zakem’s position that the one-time solicitation provided for in the settlement agreement may result in resources that are already being counted toward resource adequacy requirements in MISO Zone 7 is speculative. 10 Tr 4129.

Mr. Blumenstock responds to WPSC’s arguments on purported reliability issues that Mr. King claims are at risk in the settlement agreement. Addressing Mr. King’s argument that Consumers will likely be capacity negative in 2025, Mr. Blumenstock argues that the 28 ZRC capacity shortfall Mr. King calculated is insignificant as “a small magnitude surplus *or* shortfall can shift over a relatively short period of time. This is why the Company implements a strategy of maintaining approximately 200 ZRCs of capacity surplus.” 10 Tr 4131 (emphasis in original). Mr. Blumenstock posits that Mr. King’s capacity position calculation is also flawed as it “relies on the exclusion of capacity acquired through the one-time solicitation . . .” 10 Tr 4131 (emphasis in original). Mr. Blumenstock further provides that Mr. King’s “claim that the Company could be capacity negative in 2025 would assume the Company is wholly unsuccessful in its one-time solicitation—that 0 ZRC of capacity are acquired through a Request for Proposals soliciting up to 700 ZRCs.” 10 Tr 4131. Mr. Blumenstock avers that Mr. King’s testimony fails to explain how the equalization adjustment factor used in his capacity position is calculated or appropriately used. 10 Tr 4133.

Mr. Blumenstock responds to the BMPs’ testimony by Mr. Polich that “the Company did not appropriately consider biomass plants in this IRP” 10 Tr 4135. Mr. Blumenstock opines that “the Company is not under any obligation to enter new PPAs with the BMPs or extend the BMPs’ existing contracts.” 10 Tr 4135. Mr. Blumenstock asserts that “the Company did consider biomass plants in the development of the IRP. The Company considered biomass plants as it began its modeling process, but due to the fact that those resources were not viable options on an

economic or cost basis, biomass plants did not pass the Company's resource screen process.

10 Tr 4136. Mr. Blumenstock notes that "the plants which make up the BMPs are included in the PCA through the end of their current PPA terms." 10 Tr 4136. Mr. Blumenstock opines that "the flaw in the BMPs' position is that the Company did not have adequate information to determine the cost of new PPAs or PPA extensions with the BMPs in the development of this IRP" and "throughout this proceeding, the BMPs have failed to produce any evidence in the record establishing the costs that the BMPs could agree to in new PPAs or PPA extension[s]."

10 Tr 4136.

Mr. Blumenstock addresses Mr. Polich's testimony making recommendations to the proposed settlement agreement, arguing that "Paragraph 22 of the Settlement Agreement provides that if the Commission rejects or modifies the Settlement Agreement or any provision of the Settlement Agreement, the Settlement Agreement shall be deemed to be withdrawn." 10 Tr 4137.

Mr. Blumenstock also asserts that the BMPs' requested modifications to the settlement agreement are "beyond the scope of this contested settlement." 10 Tr 4138.

Mr. Blumenstock responds to Mr. Polich's claims that the settlement agreement will result in Consumers having "excess capacity between 2023 and 2030 and capacity shortages between 2031 and 2038." 10 Tr 4139. Mr. Blumenstock elaborates that "the Purchase Sale Agreement ('PSA') for [the Covert] plant provides for the purchase in 2023" and "Mr. Polich has also not established that the Company has any ability to move the start date of the Covert Plant purchase." 10 Tr 4140. Further, Mr. Blumenstock posits that "even if the Covert Plant does provide surplus energy and capacity for a short period, the Company can monetize the energy and capacity of the Covert Plant by selling it into the MISO markets and using the resulting revenue to lower power supply costs to

the benefit of customers.” 10 Tr 4141. Responding to Mr. Polich’s assertion that the one-time solicitation is not needed until 2030, Mr. Blumenstock opines that:

the one-time solicitation included in the proposed Settlement Agreement also supports the retirement of Campbell Units 1, 2, and 3. It is expected that the 500 ZRCs of dispatchable generation and the 200 ZRCs of intermittent and non-intermittent clean resources will provide sufficiency of supply to support retirement of the Campbell Units. However, until such resources are acquired and operational on behalf of customers, the Settlement Agreement provides for continued operation of Karn Units 3 and 4, which provide low-cost capacity for the benefit of customers. The continued operation of Karn Units 3 and 4 further addresses reliability concerns for customers.

10 Tr 4141. Mr. Blumenstock concludes that “[b]ecause the one-time solicitation will support the retirement of Campbell Units 1, 2, and 3, and the need for continued operations of Karn 3 and 4 can be assessed in the future, the BMPs have not established that the one-time solicitation is unnecessary or to the detriment of customers.” 10 Tr 4141-4142,

Mr. Blumenstock rebuts Mr. Polich’s claim that the settlement agreement will result in a capacity shortfall position in the years 2031 through 2038. Mr. Blumenstock explains that “Mr. Polich suggests that *if* a change to solar accreditation is made at MISO, the PCA would result in capacity shortfalls eight years into the future.” 10 Tr 4142 (emphasis in original).

Mr. Blumenstock posits that “the PCA was developed using current MISO solar capacity accreditation practices.” 10 Tr 4142. Mr. Blumenstock opines that “[w]hile discussions in MISO have raised the possibility of changes to solar capacity accreditation, it would be premature to adopt such changes ahead of MISO itself issuing the rule change.” 10 Tr 4142. Further, Mr. Blumenstock provides that “at the Company’s existing solar facilities, capacity accreditation, based on actual performance, has been as high as 65%” and “[w]hile the possibility of lowering the accreditation is under consideration, actual performance will ultimately dictate the levels of capacity customers receive from these resources.” 10 Tr 4142. Additionally, Mr. Blumenstock

notes that Mr. Polich’s projected capacity shortfall is to occur eight years in the future.

Mr. Blumenstock avers that Consumers “will file at least one, if not multiple IRPs between now and that time. If changes to solar accreditation occur at MISO, the Company has ample time to respond and adjust the PCA.” 10 Tr 4143-4144.

Mr. Blumenstock responds to Mr. Polich’s arguments that the one-time solicitation proposed in the settlement agreement is “deeply flawed.” 10 Tr 4144; 10 Tr 4289. In response to Mr. Polich’s claims that “the one-time solicitation will favor existing generation facilities[,]” specifically due to “engineering, financing, and construction time limitations, as well as delays in the MISO interconnection process[,]” Mr. Blumenstock “disagrees that this is a flaw in the design of the solicitation.” 10 Tr 4144. Mr. Blumenstock posits that “the resources acquired in the one-time solicitation will help replace the capacity and energy lost by Campbell Units 1, 2, and 3 in 2025” and “[f]urthermore, beyond speculating what plants can participate, Mr. Polich fails to establish anything unreasonable about the solicitation.” 10 Tr 4144. Mr. Blumenstock avers that the resources sought in the one-time solicitation are consistent with the modeling presented by the company in its principal case.

In response to Mr. Polich’s argument that Consumers chose to exclude the BMPs from its IRP, Mr. Blumenstock avers that the settlement provides that the first tranche of the solicitation requires “dispatchable, nonintermittent generation *capable* of dispatching up or down in every hour of the year in response to wholesale energy market signals.” 10 Tr 4146 (emphasis in original) (quoting Settlement Agreement, p. 6); *see also*, 10 Tr 4272. Mr. Blumenstock argues that Mr. Polich has asserted throughout these proceedings “that the BMPs’ ‘generation facilities can provide *around the clock*, renewable, *dispatchable* and reliable power generation.’” 10 Tr 4146 (emphasis in original) (quoting 7 Tr 2684). Mr. Blumenstock concludes that Mr. Polich’s testimony with regard

to the fact that the BMPs are dispatchable has been inconsistent. 10 Tr 4146. Additionally, Mr. Blumenstock provides that “certain BMPs are offered into the MISO Day-Ahead Market as units which can dispatch on an hourly basis. Since the MISO Day-Ahead Market clears the day prior to operation, the plants are provided dispatch notice prior to actual operation.” 10 Tr 4147.

Mr. Blumenstock rebuts Mr. Polich’s claim that the term “clean capacity resources,” is not defined in the settlement agreement. Mr. Blumenstock asserts that “[t]he Company’s generation portfolio includes fossil fuel and clean capacity resources such as solar and hydro generation.” 10 Tr 4147. Mr. Blumenstock provides that “[t]he Settlement Agreement specifically provides that ‘[t]his tranche will seek intermittent resources and dispatchable, nonintermittent clean capacity resources (*including battery storage resources*) providing capacity which meets the Local Clearing Requirement of MISO Zone 7.’” 10 Tr 4148 (emphasis in original) (quoting Settlement Agreement, p. 6). Mr. Blumenstock argues that “[s]ince the Settlement Agreement provides ‘battery storage resources’ as an example of the ‘dispatchable, nonintermittent clean capacity resources’ that can participate in the second tranche, the Settlement Agreement is not ‘very ambiguous,’ as Mr. Polich claims.” 10 Tr 4148 (citing 10 Tr 4280).

Mr. Blumenstock addresses Mr. Polich’s arguments that the one-time solicitation “‘will likely result in Consumers acquiring [a] substantial amount of natural gas capacity in addition to the Covert capacity’” and “‘volatility of natural gas pricing.’” 10 Tr 4148 (quoting 10 Tr 4281). Mr. Blumenstock dismisses Mr. Polich’s arguments as speculation and asserts that Consumers witness Brian D. Gallaway addressed gas prices in the initial record of this case and “‘established that gas price volatility is not expected to continue into the future.’” 10 Tr 4148. Further, Mr. Blumenstock asserts that “the Company will have an incredibly diverse resources portfolio that includes: pumped storage and hydro generation, gas generation, wind generation, solar

generation, energy efficiency, DR, and emerging technologies such as grid modernization and battery storage to meet the future demand of its customers.” 10 Tr 4148-4149. Mr. Blumenstock also posits that “[t]he Company maintains PPAs with numerous technology types.” 10 Tr 4149.

Mr. Blumenstock addresses Mr. Polich’s final concern with the one-time solicitation, that the one-time solicitation will result in “‘only intermittent generation because solar generation with battery storage will likely be too expensive to compete with solar generation without battery storage and due to shortages of materials.’” 10 Tr 4149 (quoting 10 Tr 4281). Mr. Blumenstock again dismisses this argument as speculation and opines that “[t]he one-time solicitation is a competitive bidding process which will consider the value of the resources which are bid. If certain resources are ‘too expensive,’ as Mr. Polich claims, that issue will naturally be resolved through the ranking of eligible bids.” 10 Tr 4149.

Addressing Mr. Polich’s testimony that the settlement agreement does not meet the intent of being carbon neutral by 2040 as stated in the settlement agreement, Mr. Blumenstock replies that “[p]aragraph 16 of the Settlement Agreement merely reiterates that the Company’s filed IRP ‘set forth a proposal to be Carbon Neutral by 2040 and retire all coal generation by 2025.’” 10 Tr 4149 (quoting Settlement Agreement, p. 13). However, Mr. Blumenstock posits that “there is nothing in the Settlement Agreement that will necessarily impede the Company’s ability to meet its goal.” 10 Tr 4149. Further, Mr. Blumenstock provides that “the 20-year capacity plan provided by the Company in this IRP assumed cessation of the Covert Plant by May 31, 2040. The final solution in 2040 will vary dependent upon the evolution of cleaner technologies, the possibility of carbon sequestration technologies, and potential for carbon offsets.” 10 Tr 4150.

Turning to Mr. Polich’s assertion that Karn Units 3 and 4 could be designated as a system support resource (SSR) by MISO, Mr. Blumenstock posits that “[a]n SSR designation would not

be due to a capacity or energy shortfall. An SSR designation would result from an electric transmission system deficiency that must be mitigated before Karn Units 3 and 4 could be retired.” 10 Tr 4152. Mr. Blumenstock avers that “Karn Units 3 and 4 will continue to operate to ensure near-term reliability for the benefit of Consumers Energy customers. These units may be operated through May 31, 2031, depending on the Company’s capacity needs and the outcome of the Company’s resource procurement efforts.” 10 Tr 4152. Mr. Blumenstock also provides that the cost burden associated with designating Karn Units 3 and 4 as SSR units would shift to the entirety of Zone 7 and would thus not pose an increased risk to customers. 10 Tr 4152.

Mr. Blumenstock concludes that Energy Michigan, WPSC, and the BMPs have not established any basis for the Commission to reject the settlement agreement. 10 Tr 4154.

In his rebuttal testimony, Mr. Clark responds to claims raised by Energy Michigan, WPSC, and the BMPs. Specifically, Mr. Clark focuses his rebuttal testimony on: (1) reliability concerns raised by these witnesses in connection with Consumers’ retirement of Campbell Unit 3; (2) the potential volatility of MISO’s capacity planning process and its impact on the company’s customers; (3) claims that the settlement agreement fails to address the forthcoming MISO seasonal capacity construct; (4) claims that the settlement agreement will impact reliability for residents in the lower peninsula and result in a capacity shortfall between 2031 and 2038; and (5) claims regarding competitive pricing in Michigan resulting from the settlement agreement. 10 Tr 4223.

Mr. Clark responds to Mr. King’s positions on behalf of WPSC with regard to the company’s projected solar capacity additions and their accreditations. Mr. Clark posits that the company is confident that its solar capacity expansion will be successful despite issues with supply chain and local zoning and “to the extent that the Company experiences minor delays beyond the 2025-2026

planning year, it continues to have sufficient capacity to reliably serve its load as a result of the continuing operation of Karn Units 3 and 4 and the one-time solicitation proposed in the Settlement Agreement.” 10 Tr 4227. With respect to a potential reduction in solar capacity accreditation, Mr. Clark opines that “the current ELCC is 50% of a solar generator’s installed capacity, and there is no certainty of timeline for a reduction from the current MISO practice.” 10 Tr 4227.

Mr. Clark rebuts Mr. King’s testimony “that a continued reduction to the Company’s PRMR is not reasonable,” stating that “[w]hile the Company’s forecasted load may be increasing, the Company’s internal waste reduction and demand response programs are also increasing, thereby offsetting a large portion of the growth.” 10 Tr 4227. Mr. Clark adds that “the planning reserve margin (‘PRM’) provided by MISO is decreasing, thereby allowing the Company’s PRMR to decrease rather than increase.” 10 Tr 4227-4228 (footnote omitted). Mr. Clark provides that “[t]he Company’s most recent capacity demonstration filing reflects that the PRM provided by MISO dropped from 8.70% for planning year 2022-2023 to 7.40% for planning year 2025-2026.” 10 Tr 4228 (footnote omitted). Mr. Clark notes that “[t]he Planning Year 2022-2023 Loss of Load Expectation Study Report indicates that the 2025-2026 planning year PRM decreased slightly from the 2022-2023 planning year PRM primarily based upon expected new unit additions.” 10 Tr 4228.

Addressing Mr. King’s argument that Consumers’ IRP is “based almost entirely on a 700 MW speculative solicitation of both dispatchable and intermittent resources[,]” Mr. Clark posits that “the Company has projected sufficient capacity for planning year 2025-2026, even without the additional 700 ZRCs of capacity proposed to be acquired via the solicitation.” 10 Tr 4228 (quoting 10 Tr 4302-4303). Mr. Clark opines that “neither a short delay in the onboarding of this

additional capacity nor a lack of available additional economic capacity would have a material, detrimental impact to the Company's immediate capacity position[,]” which would be reviewed subsequently in later IRP filings. 10 Tr 4229.

Mr. Clark responds to Energy Michigan's testimony from Mr. Zakem that “the Settlement Agreement will impact resource adequacy and the competitive market because the 500 ZRCs of dispatchable capacity that the company is seeking via solicitation will not necessarily be in addition to what is already being counted toward LRZ 7's resource adequacy requirements.” 10 Tr 4229. Mr. Clark argues that “Consumers Energy, like all other LSEs, is responsible for ensuring that it has adequate supply to meet its customers' needs.” 10 Tr 4229. Mr. Clark posits that “the Company has a requirement to serve its own customers' load while meeting applicable MISO requirements. The Company does not have an obligation to ensure LRZ 7 has adequate capacity for all LSEs to meet their customers' supply needs.” 10 Tr 4229.

Addressing Mr. Zakem's concerns that the settlement agreement is anti-competitive, Mr. Clark adds that:

Other LSE's, [sic] like Energy Michigan's AES [alternative electric supplier] members maintain the obligation to serve their own load and to ensure equitable contribution to reliability requirements. Consumers Energy is not responsible to provide a reliability backstop for the benefit of AESs unless the requirement to provide backup capacity is triggered by an AES's failure to meet its own four-year forward capacity obligations as required under Public Act 341 of 2016.

10 Tr 4230. Mr. Clark avers that “[o]ther LSEs have been aware of the Company's PCA since June of 2021[,] which has provided ample time to secure resources they may need to satisfy their own capacity obligations.” 10 Tr 4231. Further, Mr. Clark argues that “the Company has not issued the one-time solicitation yet and therefore, other LSEs continue to have the opportunity and ability to secure resources they may need to satisfy their own capacity obligations prior to the issuance of the one-time solicitation.” *Id.* Mr. Clark posits that “[b]ased on Staff's March 25,

2022 Capacity Demonstration Results report² filed in Case No. U-21099, all LSEs met their filing requirement detailing how the necessary capacity resources will be met for the Planning Year 2025-2026 (with one exception).” *Id.* (footnote omitted). Mr. Clark opines that “since all LSEs provided capacity projections through Planning Year 2025-2026, the 500 ZRCs of capacity that the Company will solicit for starting in 2025 should have no impact on an LSE who should have already committed capacity for the Planning Year 2025-2026.” 10 Tr 4231.

Mr. Clark then turns to the assertion of Mr. King on behalf of WPSC and Mr. Zakem on behalf of Energy Michigan on the impact the settlement agreement will have on resource adequacy. Mr. Clark avers that neither party provided specific information showing reliability risks to WPSC or Energy Michigan’s members. 10 Tr 4233.

C. Initial Briefs

1. Energy Michigan

Energy Michigan contends that the Commission is required to determine that an electric utility’s IRP “represents the most reasonable and prudent means of meeting the electric utility’s energy and capacity needs.” Energy Michigan’s initial brief, pp. 1-2 (quoting MCL 460.6t(8)(a)) (emphasis in original). Energy Michigan further posits that Rule 431 requires that for approval of a proposed contested settlement agreement, the Commission must find that “the settlement is in the public interest, represents a fair and reasonable resolution to the proceeding, and, if the settlement is contested, is supported by substantial evidence on the record as a whole.” Energy Michigan’s initial brief, p. 2 (quoting Rule 431(5)(c)). Energy Michigan avers that “[t]he Commission’s administrative rules may not overrule the underlying statute.” Energy Michigan’s

² Consumers testimony references the Capacity Demonstration Results which can be accessed on the Commission’s website at: <https://mi-psc.force.com/sfc/servlet.shepherd/version/download/0688y000002Qy56AAC> (accessed June 6, 2022).

initial brief, p. 2. Energy Michigan argues that “when a statute and an administrative rule conflict, the statute necessarily controls. While administrative agencies have what have been described as ‘quasi-legislative’ powers, such as rulemaking authority, these agencies cannot exercise legislative power by creating law or changing the laws enacted by the Legislature.” *Id.* (quoting *Imagine Entertainment, Inc v Dep’t of Treasury*, 334 Mich App 658, 664; 965 NW2d 720 (2020)). Energy Michigan posits that under this precedent, the Commission must consider whether the IRP appropriately balances the factors enumerated under Section 6t(8)(a) of Act 341, including: (1) resource adequacy and capacity to serve anticipated peak electric load, applicable planning reserve margin, and local clearing requirement; (2) reliability; and (3) competitive pricing. Energy Michigan’s initial brief, pp. 2-3 (citing MCL 460.6t(8)(a)(i)(iii-iv)). Energy Michigan argues that “[b]ecause Consumers’ proposed settlement [agreement] would have a detrimental effect on resource adequacy, reliability and competitive pricing in Michigan, the Commission should reject Consumers’ proposed Settlement Agreement.” Energy Michigan’s initial brief, p. 3.

Energy Michigan asserts that the proposed settlement agreement fails to meet the standards set forth in Section 6t(8) of Act 341 and is not in the public interest. *Id.* Energy Michigan cites to the record to demonstrate that “the Company is proposing to solicit capacity from wholesale generators that may exist in LRZ 7.” *Id.* (quoting 10 Tr 4229). Energy Michigan argues that changing ownership of resources that already exist in Zone 7 to meet Consumers’ capacity needs “has adverse effects on resource adequacy, reliability, and competitive pricing.” Energy Michigan’s initial brief, p. 3. Energy Michigan argues that while Consumers “does not believe that it has any responsibility for the rest of Michigan (*i.e.*, LRZ 7)[,]” the Commission “has a statutory responsibility to consider resource adequacy and reliability under the requirements of Section 6t.” *Id.*, pp. 3, 4.

Energy Michigan opines that if the one-time solicitation proposed in the settlement agreement is necessary, “the acquisition of 500 MW of existing in-zone capacity would not actually contribute to resource adequacy” *Id.*, p. 4. Additionally, Energy Michigan posits that if Consumers does not need the capacity represented by the one-time solicitation, “that solicitation is not the most reasonable and prudent means of meeting the utility’s capacity needs, as it would lead to an oversupply” and thus “has the potential to cause a market power issue.” *Id.*

Finally, Energy Michigan “disputes the characterization of this settlement process as involving all parties or as being open to negotiation on the concerns that Energy Michigan expressed in its testimony and briefs.” *Id.*, p. 5. Energy Michigan claims that it “was never invited to a settlement meeting, and Energy Michigan’s comments on the draft settlement agreement were neither welcomed nor considered, as [it was] explicitly told that no changes to the draft [it was] sent would be considered.” *Id.*

Thus, Energy Michigan requests that the Commission reject the proposed settlement agreement as it would negatively affect resource adequacy, reliability, and competitive pricing in Michigan. *Id.*

2. Michigan Environmental Council, Natural Resources Defense Council, Inc., Sierra Club, and Citizens Utility Board of Michigan

MNS contends that the settlement agreement meets all of the requirements of Rule 431 and should be approved.

MNS asserts that the settlement agreement is in the public interest because it results in the closure of the Campbell plant and Consumers’ exit from coal generation by 2025, and this step is critical to addressing the climate crisis and complying with the MI Healthy Climate Plan as shown in Mr. Jester and Mr. Gignac’s testimony. MNS’ initial brief, p. 4 (citing 10 Tr 4330, 4375).

MNS asserts that the settlement agreement benefits the public health in other ways as well,

through the increase to solar resources, the avoidance of the construction of new gas plants, and the removal of numerous other air pollutants (in addition to carbon dioxide) which contribute to numerous premature deaths each year. MNS' initial brief, p. 5 (citing 7 Tr 2426).

MNS notes that the retirement of the Campbell plant provides cost benefits to ratepayers as well. MNS contends that the undisputed evidence in the case showed that Campbell Units 1 and 2 are uneconomic. With respect to Campbell Unit 3, responding to WPSC's argument that this closure should be delayed, MNS notes that the settlement agreement is not severable, making it impossible for the Commission to simply adjust that timeline but approve the settlement agreement. MNS argues that such a delay would be harmful to ratepayers because the retirement of Campbell in 2025 will save customers more than \$150 million. MNS' initial brief, p. 8 (citing 10 Tr 4327).

MNS asserts that the settlement agreement is also in the public interest and a fair and reasonable resolution of the case because "it formalizes two important components of a cleaner grid: Consumers' solar ramp-up from its previous IRP; and faster deployment of battery storage investments" MNS' initial brief, pp. 8-9. MNS posits that Section 3 of the settlement agreement accelerates the transition to cleaner energy while reserving cost approval for later rate cases. MNS further indicates that the settlement agreement is in the public interest because it provides for stakeholder engagement prior to Consumers' first competitive solicitation for batteries (Section 3) and provides that the second tranche of the one-time ZRC solicitation will include battery storage resources (Section 6.b.ii.). Citing the testimony of Mr. Jester and Mr. Blumenstock, MNS contends that:

Consumers' battery proposal is a fair and reasonable settlement term for three reasons: (1) it will 'bolster Consumers' maintenance of its PRMR'; (2) it will 'support resource adequacy in Zone 7'; and (3) it may 'lead to the development of new battery storage resources within Zone 7.' The addition of battery storage

resources also addresses commodity price risks by providing ‘flexibility to adjust to changes in fuel costs, technology cost, electric demand, or the business environment’ and contributing to the diversification of Consumers’ generation supply. Finally, because Consumers proposed to advance its battery storage investment in response to testimony from Commission Staff, MNS, and other parties, this settlement term reflects the input of parties who represent the public interest.

MNS’ initial brief, p. 10 (quoting 10 Tr 4124, 4339).

MNS posits that the settlement agreement also benefits customers by removing the possibility of the CMS acquisitions which had affiliate transaction issues, significant costs, and significant operational risks. MNS points out that the settlement agreement also benefits ratepayers financially by providing for a 9% ROE to calculate the WACC for the Campbell regulatory asset (Section 5), which is more favorable than the 9.9% ROE approved in Case No. U-20963. MNS notes that Section 13 of the settlement agreement provides for the donations to low-income programs for the remaining term of the Campbell regulatory asset, and further provides that these funds will not be recovered from ratepayers. MNS’ initial brief, pp. 12-15 (quoting 10 Tr 4336). Thus, MNS points out, the settlement agreement facilitates the retirement of aging coal units while providing for lower costs for ratepayers and the funding of low-income bill assistance programs. MNS’ initial brief, p. 15.

MNS argues that the settlement agreement avoids the problematic aspects of Consumers’ original PCA while retaining the benefits, noting that the settlement continues the ramp up of solar PPA procurement, retains the 50/50 ownership-to-PPA ratio, and retains the existing FCM calculation. MNS also points to provisions that benefit the communities that will be affected by the Campbell retirement including community engagement and transition plans (Section 7.b.). *Id.*, pp. 16-19.

Responding to WPSC's arguments, MNS asserts that the settlement agreement will actually help improve resource adequacy. MNS notes that:

the Settlement will add thousands of zonal resource credits (ZRCs) to Zone 7, including:

- 1,114 ZRCs through the acquisition of the Covert combined-cycle gas plant;
- a new battery storage program in the 2024-27, which will add 71 ZRCs of new capacity;
- 250 ZRCs of new solar generation by the 2025/2026 planning year, increasing to 852 ZRCs by 2028/2029, with further increases throughout the 2030s; and
- 94 ZRCs of demand-side resources (EWR and DR) by 2025/26, increasing to 231 ZRCs by 2028/29, with further increases in later years.

MNS' initial brief, p. 20 (citing 10 Tr 4347-4350; Settlement Agreement, paragraphs 1-3; Exhibit A-14, p. 9; and Exhibit MEC-79, p. 1). MNS highlights Mr. Jester's testimony that for the 2025/2026 planning year the settlement agreement will result in an estimated net increase of 127 ZRCs, and for the 2028/2029 planning year a net increase of 923 ZRCs. MNS' initial brief, p. 20 (citing 10 Tr 4349-4350). Added to this is Consumers' obligation to seek PPAs for up to 200 additional ZRCs (Section 6.b.ii.). MNS observes that the Staff agrees that resource adequacy will be strengthened, noting Mr. Proudfoot's testimony that Zone 7 resources will increase, under the terms of the settlement agreement, by approximately 400 ZRCs by 2025. MNS' initial brief, p. 22 (citing 10 Tr 4405-4406). MNS contends that the settlement agreement thereby complies with the statutory requirement that the IRP ensure resource adequacy and capacity. MCL 460.6t(8)(a)(i). MNS also argues that Mr. Jester and Mr. Blumenstock refuted Mr. King's calculations and arguments. MNS' initial brief, p. 23 (citing 10 Tr 4354-4356, 4130-4134).

Finally, MNS points to the diversity of the parties that are signatories to the settlement agreement as evidence that the agreement is in the public interest and argues that, by comparison, the objecting parties' interests are relatively narrow. MNS asserts that Energy Michigan is a trade group with narrow business interests; WPSC is a power supply cooperative with a contractual

interest in opposing the Campbell retirement; the BMPs seek only to extend their PPAs with Consumers; and Mackinac submitted no evidence and evinces only an ideological opposition to closing coal plants. MNS' initial brief, pp. 25-27. MNS argues that the settlement agreement satisfies the Rule 431 criteria and should be approved. *Id.*, pp. 27-28.

3. Mackinac Center for Public Policy

Mackinac argues that the Commission should reject the settlement agreement because it does not represent "the most reasonable and prudent means of meeting the electric utility's energy and capacity needs" as required in the language of MCL 460.6t(8)(a). Mackinac's initial brief, p. 3 (quoting MCL 460.6t(8)(a)). Mackinac also contends that the settlement agreement does not meet the requirements of Rule 431(5) because it is not in the public interest and is not supported by substantial evidence on the record. Mackinac's initial brief, pp. 4-5.

Mackinac asserts that the settlement agreement is not in the public interest because it presents a risk of "systemwide instability and rapid price swings." *Id.*, p. 5. Mackinac states that this is partially due to the overreliance in the settlement agreement on acquiring additional power from the MISO market. Mackinac quotes from its exceptions to argue that MISO does not have sufficient capacity to serve the relevant demand. Mackinac asserts that the settlement agreement could cause reliability problems in MISO Zone 7 if early plant closures are "allowed to move forward without sufficient replacement capacity." Mackinac's initial brief, p. 7 (quoting Mackinac's exceptions, p. 7). Mackinac "acknowledge[s] that the proposed Settlement Agreement addresses this somewhat by acknowledging that Karn Units 3 and 4 may be required to stay in operation," but argues that the settlement agreement does not do enough to alleviate the concern about "systemwide instability and rapid price swings." Mackinac's initial brief, p. 8. Mackinac

argues that the recent results of the MISO Planning Resource Auction for Zone 7 show the potential for a shortfall.³

Mackinac further states that the settlement agreement fails to consider the recent volatility of natural gas prices. Mackinac argues that natural gas plays a “heavy role” in the settlement and thus natural gas pricing should be central to the Commission’s decision. *Id.*, p. 10. Mackinac again quotes extensively from its exceptions and argues that the settlement agreement fails to address the concerns that were laid out in the exceptions. Mackinac asserts that Henry Hub prices are at “near-historic levels” and that the price of coal compares favorably to natural gas. *Id.*, pp. 14-15. Mackinac asserts that “a reasonable and prudent path would be to rework the Company’s modelling scenarios with more realistic natural gas prices.” *Id.*, p. 15.

Mackinac further expresses concern that:

[p]er the Proposed Settlement Agreement, the Company will spend over \$30 million ratepayer dollars establishing programs specifically designed to limit customer access to electricity services during periods of higher demand (cold or hot weather): \$23,751,000 for demand response programs, and \$9,736,315 for conservation voltage reduction. These expenditures are deemed necessary because the Company is working from its wholly voluntary plan to reach net-zero CO2 emissions by designing a system that will be unable to meet customer demand, especially during periods of extreme weather.

Id., p. 16 (citing Settlement Agreement, p. 4). Mackinac continues, arguing that the settlement agreement fails to address the issues of restricted supply chains and significant price increases for certain minerals such as lithium, cobalt, and nickel. Mackinac posits that Consumers’ planned expansion of the use of batteries will still be insufficient to provide the necessary backup power

³ Mackinac’s initial brief contains numerous links to publicly available documents sourced from governmental entities or the media. None of the referenced documents are part of the record in this case. Mackinac did not present evidence in either the primary phase or the contested settlement phase of the case.

during extended periods of inclement weather, and that, in any case, developing a sufficient level of backup battery power would be prohibitively expensive. Mackinac asserts that the settlement agreement also fails to consider the significant environmental costs associated with Consumers' goal of becoming carbon neutral by 2040, which, Mackinac insists, will add to the growing level of "industry-wide instability, insolvencies, supply chain issues, and stalled development projects in the solar and wind industries." Mackinac's initial brief, p. 19.

Mackinac states that, under Section 5 of the settlement agreement, Consumers will be transferring stranded costs associated with Campbell Units 1, 2, and 3 to ratepayers as well as decommissioning costs (after a reasonableness and prudence review). Mackinac opines that an increasing level of instability is being designed into Consumers' system through the loss of large, dispatchable generation sources which are replaced by what it refers to as "weather-dependent and non-dispatchable renewable sources." *Id.*, pp. 9, 19-20.

Mackinac argues that Consumers' proposed donations to low-income programs are "a band-aid solution to the problems caused by its own decision to impose on ratepayers the cost of its wholly voluntary goal of net-zero emission by 2040 goals, as well as the systemwide costs associated with weather-dependent and variable renewable energy sources." *Id.*, pp. 20-21 (footnote omitted). Mackinac concludes that:

The Company is developing and constructing a system that precludes the use of coal and nuclear and relies solely on wind, solar, storage, and (over the upcoming two decades) slowly decreasing levels of natural gas for actual generation of electricity services for customers. Other programs such as EWR, CVR, and demand response target reduced supply and use by customers of electricity services, not the actual provision of electric service to customers. Mackinac Center objects to these measures.

Id., p. 21.

4. Michigan Energy Innovation Business Council, Institute for Energy Innovation, and Clean Grid Alliance

EIBC/IEI/CGA support the settlement agreement, noting that Rule 431 encourages parties to enter into settlement agreements when possible. EIBC/IEI/CGA contend that the settlement agreement meets all of the criteria for an approvable settlement under Rule 431(5) because the objecting parties were given a reasonable opportunity to present evidence and argument in opposition; the public interest is represented by the parties who entered into the agreement; and the settlement agreement is a fair and reasonable resolution of the proceeding that is supported by substantial evidence on the record. EIBC/IEI/CGA note that discovery continued during the contested settlement phase of the case and cross-examination took place. EIBC/IEI/CGA's initial brief, pp. 5-6. They also note the testimony from the Staff regarding the cross-section of signatories to the agreement, including parties who represent residential customers, commercial and industrial customers, advanced energy sector businesses, environmental groups, a transmission company, and third-party developers. *Id.*, p. 7 (citing 10 Tr 4407-4408). EIBC/IEI/CGA note that, under Section 6.b.ii. of the settlement agreement, Consumers is making a commitment to acquiring new clean energy resources of up to 200 ZRCs through PPAs or other third-party agreements. EIBC/IEI/CGA's initial brief, p. 7.

Responding to the objection that the settlement agreement will result in serious supply chain issues, EIBC/IEI/CGA opine that the settlement agreement turns these risks into opportunities by calling for better utilization of "Michigan manufactured components and low-carbon manufacturing" in the competitive bidding process. EIBC/IEI/CGA's initial brief, p. 8 (quoting Settlement Agreement, p. 9). EIBC/IEI/CGA aver that the concerns about pricing that have been expressed by the objectors are addressed by Consumers' commitment to continue the 50/50 company-ownership to third-party ownership construct that was approved in Case No. U-20165.

EIBC/IEI/CGA's initial brief, pp. 9-10. EIBC/IEI/CGA conclude that the settlement agreement meets the requirements of Rule 431(5) and should be approved. *Id.*, pp. 10-11.

5. Michigan Department of Attorney General

The Attorney General states that her primary concerns with Consumers' IRP are affordability, reliability, and the use of sustainable sources of energy. She contends that the settlement agreement addresses all three of these concerns. The Attorney General notes that the settlement agreement provides for the closure of Consumers' remaining coal plants and argues that this benefits public health and is consistent with Governor Whitmer's MI Healthy Climate Plan. Attorney General's initial brief, p. 8 (citing 10 Tr 4375, 4327-4330, and 4122).

Beginning with affordability, the Attorney General notes that evidence shows that the early retirement of the Campbell plant will save ratepayers \$150 million in avoidable capital expenditures. Attorney General's initial brief, p. 9 (citing 10 Tr 4327). She argues that the settlement agreement also saves money for ratepayers by eliminating Consumers' proposal to acquire the affiliated CMS plants, which avoids the potential \$515 million in immediate costs as well as future retirement costs and the unrecovered book value of Karn Units 3 and 4. Attorney General's initial brief, pp. 9-10 (citing 10 Tr 4334-4335). The Attorney General further notes that, with respect to the regulatory asset, the settlement provides for a WACC of 9.0% rather than the current ROE of 9.9%, also benefiting ratepayers. And finally, the settlement agreement provides for assistance to low-income ratepayers with direct funding of \$5 million this year and another potential \$2 million annually over the next 14 years. Attorney General's initial brief, p. 10.

Addressing reliability, she contends that the settlement agreement provides for adequate existing and new resources to meet capacity needs. Attorney General's initial brief, p. 11 (citing 10 Tr 4330-4335, 4406, 4224-4229, 4139, and 4142-4144). The Attorney General points to the

continued availability of Karn Units 3 and 4, as well as the solicitation for PPAs that will provide up to 700 ZRCs of energy and capacity beginning in 2025. She also cites to the provision that Consumers seeks 2 additional GW of new solar energy and undertake a battery storage program. Attorney General's initial brief, p. 11 (citing 10 Tr 4339). The Attorney General further states that:

the Settlement Agreement requires the Company to conduct certain evaluations and take other actions prior to the next IRP that can lead to benefits for ratepayers including, but not limited to, developing a distributed generation resource model; gathering input from the public before filing its next IRP; gauging interest in combined heat and power resources and model for the next IRP proceeding; providing total emissions for certain pollutants in the next IRP case; presenting PM2.5-related health impacts from power plant emissions in the next IRP case; conducting environmental justice screenings near power plants; and reporting on low-income customers['] participation in energy reduction and load reduction activities and rooftop solar adoption.

Attorney General's initial brief, pp. 11-12 (citing Settlement Agreement, pp. 12-16). The Attorney General urges the Commission to approve the settlement agreement.

6. Environmental Law and Policy Center of the Midwest, Ecology Center, Inc., Union of Concerned Scientists, Inc., and Vote Solar

The CEOs take the position that the contested settlement agreement is in the public interest and supported by record evidence. The CEOs contend that the settlement supports the public interest because: “(1) it aligns with important climate action goals intended to protect Michiganders; (2) it improves economic and public health outcomes; and (3) it includes beneficial modeling and community engagement commitments for the Company's next IRP.” CEOs' initial brief, p. 6 (quoting 10 TR 4375). The CEOs posit that “the Settlement Agreement is consistent with Governor Whitmer's MI Healthy Climate Plan, and is responsive to the urgency of addressing climate change.” *Id.* The CEOs opine that the settlement agreement balances the cost to Consumers associated with retirement of its coal plants with the impacts on low-income

customers. CEOs' initial brief, p. 6 (citing 10 TR 4376). The CEOs state that expert testimony in the record demonstrates avoided negative health outcomes as a benefit of the early coal plant retirements and that significant public health and environmental concerns associated with acquiring the DIG facility are avoided under the settlement agreement. CEOs' initial brief, pp. 6-7. Finally, the CEOs aver that the settlement agreement has important implications for future IRPs including the commitments to model distributed generation as a resource, conduct public health and environmental justice analyses, and provide expanded opportunities for community input and public participation. *Id.*, p. 7 (citing 10 Tr 4376). The CEOs argue the Commission should find the settlement agreement to be in the public interest.

7. Hemlock Semiconductor Operations, LLC

HSC supports the settlement and recommends that the Commission approve it. HSC's initial brief, p. 2. HSC opines that "parties were given a reasonable opportunity to present evidence and arguments in opposition to the record." *Id.*, p. 4. HSC posits that the public interest was adequately represented by parties entering into the settlement agreement as "the signatories to the Settlement Agreement represent a broad cross-section of interests" *Id.*, p. 5. HSC also notes that "the Michigan Court of Appeals has affirmed a Commission determination that the public interest was adequately represented by the Staff when the Staff was a party to a contested settlement agreement." *Id.* (citing *Attorney General v Mich Pub Serv Comm*, 237 Mich App 82, 93094; 602 NW2d 225 (1999) (*Attorney General*)). HSC opines that "all the parties who filed testimony in opposition to the settlement represent competitors of Consumers. In each case, the objecting party is seeking to advance its own particular interest, and not the public interest." HSC's initial brief, p. 6 (footnote omitted). HSC submits that the settlement agreement is a fair and reasonable resolution of the proceeding as "Consumers and others presented testimony and

arguments that the Settlement Agreement reflects significant compromise by all involved” which is “evident when comparing the details of Consumers’ initial PCA with the terms of the proposed Settlement Agreement.” *Id.* Finally, HSC posits that the settlement agreement is supported by 315 pages of transcript and 23 exhibits while the principal record in this case consisted of 4,094 pages of transcript across 9 volumes and over 500 exhibits. *Id.*, p. 7. HSC concludes that the settlement agreement “is supported by substantial evidence on the record and should be approved.” *Id.*

8. The Commission Staff

In response to the concerns raised regarding resource adequacy, the Staff responds “that this settlement agreement appropriately balances the resource adequacy concerns of Zone 7, Consumers’ need to serve the load and demand of its customers, and the benefits of Consumers’ decision to work towards becoming carbon neutral by 2040.” Staff’s initial brief, p. 4 (citing Settlement Agreement, p. 13). The Staff notes that its testimony highlights the addition of the Covert plant and the investments in renewable generation. *Id.* The Staff notes its concerns regarding resource adequacy of Zone 7, but states that:

it also understands that Consumers Energy is not tasked with providing resource adequacy for the entirety of Zone 7 at the sole expense of Consumers’ ratepayers. Staff expects all load serving entities within MISO Zone 7 to contribute the necessary capacity to meet capacity obligations at MISO and through Michigan’s State Reliability Mechanism (MCL 460.6w) and that these load serving entities will make the necessary investments to ensure that all customer needs within the zone are fully planned for. Therefore, Staff recommends that the Commission find that this settlement agreement appropriately balances the reliability needs of Zone 7 and the needs of Consumers’ ratepayers.

Staff’s initial brief, p. 5. The Staff reiterates that while the CMS plants “can bid into one tranche of the solicitation, the CMS [plants] are only able to bid in for the capacity they have available that is not currently contracted for” which “constitutes less than 500 ZRCs in 2025.” *Id.*, p. 6 (citing

Settlement Agreement, pp. 6-7; 3 Tr 138, 366). The Staff also states other resources, such as distributed energy resources, may be available by 2025, and are not currently counted within Zone 7. Further, the Staff reiterates testimony indicating “that the second tranche of the solicitation will likely result in additional new resources.” Staff’s initial brief, p. 6.

In response to the BMPs, the Staff states that, while the biomass plants are reliable resources, the Commission cannot modify the proposed settlement agreement to extend the PPA’s to 2035, because the settlement agreement is not severable, and any modification or rejection of a provision deems the settlement agreement to be withdrawn. Further, the Staff indicates that the biomass plants are able to participate in the one-time solicitation as set forth in the settlement agreement. *See, id.*, p. 7.

9. Consumers Energy Company

Consumers contends that the settlement agreement satisfies the requirements of Rule 431. Consumers’ initial brief, p. 10. Consumers argues that the signatories of the settlement agreement adequately represent the public interest and reiterates testimony from its witness, Mr. Torrey, “on the nature, scope, and diversity of parties’ interests . . .” in this case. *Id.*, p. 11. Consumers also quotes testimony from the Staff’s witness, Mr. Proudfoot, that “the 18 parties that signed ‘represent most, if not all, of Michigan’s sectors concerned with the future of energy related issues,’ thus satisfying the requirement that the parties represent the public interest.” *Id.*, p. 11 (quoting 10 Tr 4408). Consumers posits that Mr. Torrey’s and Mr. Proudfoot’s testimony demonstrates that “the signing parties ‘represent a broad, diverse group of parties advocating for the economic and environmental interests of Consumers Energy’s electric customers and the state of Michigan,’ who are also focused on ensuring the Company’s customers are provided with reliable electricity.” Consumers’ initial brief, p. 11 (quoting 10 Tr 4257).

Consumers contends that “[t]he Commission should consider the four parties that signed statements of non-objection to the Settlement Agreement in reaching a finding that the Settlement Agreement adequately represents the public interest because those parties, having had an opportunity to contest the Settlement Agreement, elected not to do so.” Consumers’ initial brief, p. 12. Similar to HSC, Consumers posits that “[t]he Michigan Court of Appeals has upheld the Commission’s finding that a utility’s and Staff’s involvement in a settlement agreement can be sufficient to ensure that the public interest is adequately represented and also found that that ‘participation of fewer than all interested parties in the negotiation does not mandate a conclusion that the signatories to the settlement did not represent the public interest.’” *Id.* (quoting *Attorney General*, p. 94). Consumers concludes that “[t]he factual circumstances presented in this proceeding meet and exceed the Commission’s requirement for ensuring that the settling parties adequately represent the public interest.” Consumers’ initial brief, p. 12.

Consumers notes that of the four parties opposing the settlement agreement—Energy Michigan, Mackinac, WPSC, and the BMPs—only three filed testimony in the present case. *Id.*, p. 13. Further, Consumers argues that “[u]nlike the broad and diverse group of parties who signed the Settlement Agreement, the three parties who submitted testimony opposing the Settlement Agreement are all business competitors of Consumers Energy.” *Id.* (citing 10 Tr 4262).

Consumers reiterates its testimony that:

Energy Michigan and Wolverine would benefit financially from the opportunity created in this proceeding to procure surplus capacity to meet their own customers’ needs at a lower cost than building their own. The BMPs would also benefit financially if they received contract extensions at the expense of other resources which make up the PCA. That kind of motivation represents the opposite of the public interest.

Consumers’ initial brief, p. 13 (quoting 10 Tr 4263). Consumers concludes that “the broad-based coalition of parties who signed the Settlement Agreement and the parties who signed statements of

non-objection are a far better representation of the public interest in this proceeding than the parties who oppose it.” Consumers’ initial brief, p. 13 (citing 10 Tr 4263).

Consumers argues that the settlement agreement represents a fair and reasonable resolution to the proceedings as it “represents a significant compromise that was negotiated in good faith and proposes to resolve this matter based on the positions of the parties in the record.” Consumers’ initial brief, p. 14. Consumers avers that the settlement agreement meets the requirements for approval set out under Section 6t of Act 341. Specifically, Consumers posits that “all 18 signing parties agree that the PCA, as provided in the Settlement Agreement, represents the most reasonable and prudent plan to meet the Company’s energy and capacity needs over the 5-year, 10-year, and 15-year time horizons” as required by Section 6t(8)(a) of Act 341. *Id.* Consumers reiterates testimony by company witness Blumenstock on the settlement agreement’s compliance with Section 6t(8) of Act 341, including how the settlement agreement: (1) ensures resource adequacy and capacity that is sufficient in quantity to serve anticipated peak electric load plus applicable PRMR and LCR; (2) ensures compliance with applicable state and federal environmental regulations; (3) ensures competitive pricing; (4) ensures reliability; (5) addresses commodity price risk and ensures diversity of generation supply; and (5) proposes reasonable and cost effective levels of peak load reduction (DR, CVR, EWR). *See*, Consumers’ initial brief, pp. 14-19. Consumers cites to testimony by the Staff that the company’s IRP PCA as revised by the settlement agreement meets the requirements of Act 341 as additional support. Consumers’ initial brief, pp. 19-20.

As noted above, Consumers argues that the settlement agreement “was supported in the extensive record created in the proceedings leading up to the filing of the Settlement Agreement, which consisted of over 4,000 pages of testimony and over 500 exhibits” as well as the additional

evidence provided on the contested settlement. *Id.*, p. 20. Consumers notes the position of company witness, Mr. Blumenstock, MNS, and the Staff that the settlement agreement is supported by substantial evidence in the record as a whole. Consumers quotes the Staff's testimony that:

As stated above, the record in this case is substantial. All issues addressed in the [Settlement Agreement] have been addressed in testimony, rebuttal, brief, exceptions, and robust discovery. The [Settlement Agreement] was filed after a full record has been developed in this case. Therefore, based on all of the above, it is Staff's opinion that this [Settlement Agreement] meets the requirements of Rule 431.

Id., p. 21 (quoting 10 Tr 4408). Further, Consumers posits that "certain objecting parties have also attempted to interject issues into this contested settlement proceeding which are not based on the initial record at all." Consumers' initial brief, pp. 21-22. Specifically, Consumers references WPSC's reliance on the company's December 1, 2021 capacity demonstration in Case No. U-21099 and the BMPs' proposal that the settlement agreement be modified to require Consumers to extend their PPAs with the represented plants. *Id.*, p. 22. Consumers concludes that the settlement agreement "is in the public interest, represents a fair and reasonable resolution of the proceedings, and is supported by substantial evidence on the record as a whole" and thus "it should be approved by the Commission in its entirety without and modifications or conditions." *Id.*

Turning to the arguments of the individual objecting parties, Consumers argues that these objections fail to provide grounds to reject or modify the settlement agreement. *Id.*, p. 23. Consumers opines that these "arguments demonstrate a self-interested concern that the Settlement Agreement will challenge their ability to profit off Consumers Energy and its customers and Michigan's hybrid deregulation construct." *Id.* Addressing WPSC's position that the settlement agreement will negatively impact reliability, Consumers avers that the settlement agreement "will

bring at least 2,084 ZRCs into MISO LRZ 7 and retire only approximately 1,400 ZRCs of capacity, with a net addition for LRZ of nearly 700 ZRCs (at least).” *Id.*, p. 24. Consumers posits that “[t]his increase will enable the Company to manage any challenges or delays associated with bringing new resources online, changes in MISO’s planning requirements that may impact the Company’s PRMR, the migration to a seasonal capacity construct, and any degradation that might be applied to solar capacity accreditation.” *Id.* Consumers then addresses claims regarding reliability and resource adequacy of WPSC, Energy Michigan, the BMPs, and Mackinac individually. *See*, Consumers’ initial brief, pp. 24-56. As these positions are thoroughly outlined above, they will not be repeated here.

Consumers concludes that “the intent and focus of the Company’s original PCA were maintained” by the settlement agreement “ensuring the Company’s clean energy transition, as initially set forth in the Company’s 2018 IRP.” Consumers’ initial brief, p. 56. Consumers argues that the PCA, as modified by the settlement agreement will “help lead a faster clean energy transformation by accelerating the Company’s exit from coal-fired generation in 2025 while increasing reliability and providing resource adequacy for customers.” *Id.* The company provides that “the Settlement Agreement will continue the Company’s competitive procurement of clean energy resources by procuring approximately 8,000 MWs of solar resources by 2040 and will also accelerate the deployment of battery storage.” *Id.*, pp. 56-57. Finally, “like the Company’s initially filed plan, the PCA, as modified in the Settlement Agreement, continues to save customers money—providing for customer savings of nearly \$600 million.” *Id.*, p. 57.

Consumers asserts that the settlement agreement “meets the requirements of the Commission’s rule for approving contested settlement agreements, Rule 431, and the requirements for approving an IRP under Section 6t.” *Id.*

10. The Biomass Merchant Plants

The BMPs first summarize the contested settlement agreement before turning to the issue of the scope of the proceeding. The BMPs aver that their position is not beyond the scope of this IRP proceeding as their “objections in this proceeding are that the modified IRP fails specific statutory requirements of MCL 460.6t(8)” and that the “most reasonable and prudent means” under the statute requires the review of alternative plans which is what the BMPs offered in this case. BMPs’ initial brief, p. 6, 8 (emphasis omitted). The BMPs reiterate their objections, which were overruled by the ALJ to the company’s testimony, again claiming they did not have an opportunity to respond. *See, id.*, pp. 9-10.⁴

The BMPs argue that the settlement agreement fails the resource adequacy and reliability requirements under the statute as there is a shortfall in ZRCs. Thus, the BMPs state that the settlement agreement should be modified because “[c]ontinuing to purchase capacity and energy from the BMPs through 2035 would, in fact, correct both that statutory defect and the Company’s strategic goal.” *Id.*, p. 11. The BMPs further argue that the settlement agreement also fails to recognize the likelihood of the reduction of solar accreditation “down as low as 30% in the next

⁴ The Commission notes that the BMPs made several references to appealing evidentiary rulings throughout its initial brief. *See*, BMPs’ initial brief, pp. 9, 10, 36, 42-43. The Commission’s rules set forth the standard for appealing rulings of presiding officers. *See*, Mich Admin Code, R 792.10433 (Rule 433). In part, Rule 433(3) states that “[a]n offer of proof shall be made in connection with an appeal of a ruling excluding evidence” and that “[i]f the ruling excluded written evidence or evidence that refers to documents or records, the offer of proof shall consist of a copy of the evidence, documents, or records.” In addition, Rule 433(4) states that an application for appealing a ruling of a presiding officer “shall be supported by a clear and concise brief, pursuant to the provisions of R 792.10434, stating the basis for the appeal and showing that it complies with the provisions of this rule. The brief shall be supported by specific factual allegations as appropriate.” The Commission finds that the BMPs have not met these minimum standards set forth under Rule 433. Therefore, the Commission denies any appeal of rulings made by the presiding officer in this proceeding as set forth in the BMPs’ initial brief.

several years.” *Id.*, p. 12 (footnote omitted). The BMPs reiterate the testimony to aver that resource adequacy concerns are compounded by issues surrounding solar and battery storage and that the settlement agreement fails to address “the question of what energy is being stored, solar or fossil fuel generated energy. Solar energy can only be stored if that solar production exceeds load. If the load exceeds the solar generation, the energy being stored is from fossil fuel generation.” *Id.*, p. 15.

The BMPs reiterate their concern regarding Consumers’ “use of an incorrect solar capacity factor” which it avers “is 20.6% greater than the average capacity factor of all solar generation facilities currently operating in Consumers’ service territory.” *Id.*, pp. 4, 17. The BMPs state “[i]n contrast to the proposed solar capacity, the generation from the Biomass Plants is well known and MISO is not considering revisions to their ZRC accreditations.” *Id.*, p. 22.

Citing MCL 460.6t(8)(b), ED 2020-10, and the IRP filing requirements, the BMPs argue that “despite the fact that the Biomass Plants are located within Consumers’ service territory,” the settlement agreement disregards “the economic impact of the potential closure of those plants on the communities in which they are located.” BMPs’ initial brief, pp. 22-23. Therefore, the BMPs aver that the settlement agreement violates the statutory mandate because it “chooses to import energy into Michigan from other states” and “supports out-of-state construction and production rather than in-state construction, construction upgrades, construction maintenance and in-states generation.” *Id.*, p. 24.

The BMPs contend that the settlement agreement also does not meet the requirements in MCL 460.6t(8)(a)(v) because it fails to address potential future lack of capacity and that any early retiring plant could be designated as a system support resource (SSR), requiring it to remain in operation and that the “designation costs can run into significant millions of dollars.” BMPs’

initial brief, pp. 25-26. Similarly, under MCL 460.6t(8)(a)(vi), the BMPs aver that the settlement does not “appropriately balance the diversity of generation resources” which “impacts that commodity price risk” under MCL 460.6t(a)(v). BMPs’ initial brief, p. 26. The BMPs reiterate the record testimony to support this contention arguing that “the first tranche of the One Time Solicitation will almost certainly result in Consumers acquiring natural gas capacity” which will likely include the CMS plants, “all of which are natural gas fired generation” and that this “concentrated amount of natural gas fired generation has commodity price risk” *Id.*, pp. 27-28.

The BMPs restate the position that Consumers has inappropriately excluded generation from the biomass plants from the settlement agreement and that the company improperly relied on “the cost of new Biomass construction even though the Biomass Plants are existing construction, not new construction.” *Id.*, p. 30 (emphasis omitted). Reiterating record testimony, the BMPs aver that the settlement agreement violates the “statutory obligation under MCL 460.6t(1)(f)(iii) to include ‘any supply-side and demand-side resources that reasonably could address any need for additional generation capacity’” BMPs’ initial brief, p. 33. The BMPs further claim that the biomass plants are excluded from the one-time solicitation based upon the criteria set forth in the settlement agreement. *See, id.*, pp. 35-38.

The BMPs contend that the settlement agreement violates ED 2020-10 and Michigan’s Healthy Climate Plan. *Id.*, p. 38. In support of this position, the BMPs state:

The Settlement Agreement simply fails to consider the environmental benefits of the Biomass Plants as compared to the non-intermittent fossil fuel generation that will be acquired under the IRP as modified by the Settlement Agreement. It also fails to consider the unequaled ability of the Biomass Plants to help Consumers reach the goals of both Executive Directive 2020-10 and Michigan Healthy Climate Plan. The Biomass Plants’ fuel composition is described in detail in Mr. Polich’s testimony. The Biomass Plants are not only net-zero carbon generation, they have

the further benefit of preventing the release of Methane from decomposing forest wood waste into the atmosphere.

BMPs' initial brief, p. 40 (footnote omitted). The BMPs further argue that the environmental benefits of biomass fueled generation include a much smaller land use than solar and that "[c]ontinuing to purchase 188 MW of energy from the existing Biomass Plants means that between 1,128 to 1,504 acres of land can be left undisturbed by an equivalent amount of solar projects." *Id.*, p. 42.

The BMPs restate that the ALJ erred in numerous evidentiary rulings including sustaining objections and limiting the time for cross-examination. *See, id.*, p. 43. In conclusion, the BMPs "object to the Settlement Agreement as presented and request that it be amended to include a provision pursuant to which Consumers will continue to purchase capacity and energy from the Biomass Plants after the end dates of their current contracts until 2035." *Id.*, p. 44.

11. Citizens Utility Board of Michigan

CUB argues that the settlement agreement improves upon Consumers' original PCA and is in compliance with Rule 431. CUB states that the settlement agreement improves the PCA as it improves the future analyses of marginal line losses and avoided transmission and distribution costs and that:

[w]hile the Settlement Agreement does not require Consumers to reevaluate residential DR potential in this IRP . . . its commitment to collecting and reporting valuable marginal line loss data and including marginal line losses and avoided T&D costs in its evaluation of all distributed resources in future IRPs is a fair and reasonable compromise.

CUB's initial brief, p. 3. CUB also notes that the settlement agreement removes the 20% FIM Consumers was seeking in this proceeding. *Id.*

CUB notes that the parties signing the settlement agreement "represent a broad spectrum of the public interest, including the interests of residential ratepayers, commercial and industrial

ratepayers, businesses, and environmental groups” demonstrating the public interest is adequately represented. *Id.*, p. 4 (citing 10 Tr 4407-4408). CUB reemphasizes its testimony and avers that the substantial record demonstrates that the settlement agreement “and provides a fair and reasonable resolution of their respective concerns in this proceeding.” *Id.*, p. 5. Finally, CUB states that “the objecting parties have been given a reasonable opportunity to present evidence and arguments in opposition” to the contested settlement agreement, therefore satisfying all requirements of Rule 431. CUB’s initial brief, p. 6.

12. Wolverine Power Supply Cooperative

WPSC argues that the settlement agreement fails to meet the requirements of Rule 431. WPSC avers that the settlement agreement is not in the public interest as it will allow the retirement of Campbell 3 in 2025 which “will further stress Michigan’s already-strained grid system” and that this “fails to represent a fair and reasonable resolution to the proceeding.” WPSC’s initial brief, pp. 2-3. Pointing to the record and the PFD, WPSC states that a 2025 retirement of Campbell 3 is not well-supported. WPSC argues that approval of the settlement agreement “requires a set of parallel, perfect, and, therefore, unlikely outcomes” and lists those outcomes as follows:

(1) despite MISO’s projections, Zone 7 realizes sufficient resources to serve Michigan, (2) Consumers realizes declining load growth, despite economic projections and announced load growth; (3) Consumers’ one-time solicitation is fully successful in acquiring 700 incremental Zonal Resource Credits (“ZRC”) that are installed and delivered in less than three years, and (4) Consumers realizes the outcome of its modeling—a complete disconnection from the rest of Michigan’s grid.

Id., p. 3 (footnote omitted).

WPSC states that:

[w]hen reviewing more current data from Consumers’ own capacity demonstration filing in Case No. U-21099, which shows a 271 ZRC deficit in 2022 or 425 ZRC

lower than the PCA even with the same supply mix, . . . unless it acquires a material portion of the solicitation, Consumers will be capacity negative in 2025, even with the Covert purchase and keeping Karn Unit 3 and 4 online through 2030. (Testimony of Thomas King, 10 Tr 4303; Rebuttal Testimony of Thomas King, 10 Tr 4311-4312.)

Id., p. 4 (emphasis in original). WPSC further argues that the settlement agreement's effort of allowing a one-time solicitation of 700 ZRCs to combat reliability concerns from the early retirement "does not ensure Consumers customers are shielded from resource adequacy shortfalls in Zone 7 – the projects must actually be built and the 700 ZRCs of dispatchable and intermittent resources likely cannot be built in time." *Id.*, p. 4. Continuing, WPSC points out that "the proposed solicitation will not create any incremental (i.e., new) Zone 7 capacity" and is merely another path to utilize the CMS plants as originally proposed in the PCA. *Id.* Reiterating its testimony, if Campbell 3 is replaced with existing Zone 7 capacity there will be a net negative capacity position in the zone which, WPSC avers "places Michigan on a path toward load shed (e.g., blackouts) that is likely to harm Michigan residents." *Id.*, p. 6 (citing 10 Tr 4312).

WPSC reiterates its testimony that, despite Consumers' assumption, the market reality is that there is a declining PRMR between 2022 and 2025, and that it "it conflicts with MISO's statements of increasing load forecasts." *Id.*, p. 7 (citing 10 Tr 4305 and Exhibit WPSC-6). WPSC further points to developmental projects which will result in incremental load increases and argues that Consumers' estimates of increases in DR are not supported by any evidence indicating that such is possible. WPSC further states that the company's assurances that there is time to address the shortfall in the future is insufficient and that "it is unreasonable for Consumers to utilize an unsupported, lower reserve margin for the future." *Id.*, p. 8.

WPSC further argues that, while the first 500 ZRCs for the proposed solicitation are likely to come from existing Zone 7 resources, "the second tranche of 200 ZRCs are likely to be procured

from intermittent resources” and that “[t]he record is devoid of evidence regarding where the needed resources would come from.” *Id.*, p. 9 (citing 10 Tr 4312). WPSC states that the denial that the solicitation is speculative “demonstrates a fundamental misunderstanding of the current renewables landscape” and even as “more solar resources are added to the grid, less benefit is realized and the solar capacity accreditation declines to match performance.” *Id.* (citing Exhibit WPSC-8). WPSC reiterates its position that the 500 MW is unreasonable noting that:

[e]ven if the proposed 500 MW of projects were able to procure materials and Consumers is capable of acquiring and utilizing the nearly 3,500 necessary open acres of Michigan land, the projects would also need to achieve the local government approvals, complete MISO’s byzantine generation queue process, and complete transmission improvements necessary to facilitate construction and interconnection—all within the limited time available.

Id., p. 10.

In addition, WPSC avers that the settlement agreement inappropriately requires Consumers to be treated as an island rather than an integrated and interconnected participant in the Michigan electric grid. WPSC argues that “[g]iven the likely capacity shortfall in Zone 7, the [settlement agreement’s] failure to address transmission deficiencies will exacerbate the problems created by hastily retiring generation resources. If one of the few existing ties fail or export capability from other areas is reduced, the only other option will be load shed.” *Id.*, p. 11 (footnote omitted).

WPSC concludes that, under Rule 431, the Commission must deny the settlement agreement as it “is not supported by *any* evidence within the record, and certainly is not supported by *substantial* evidence on the record” but rather that the record demonstrates additional modeling and analysis is needed to support an early retirement of Campbell Unit 3. *Id.*, p. 12 (emphasis in original). WPSC further states that “[r]ushing the retirement of Campbell Unit 3 may allow the Commission to continue forward with its admirable goal of reducing Michigan’s carbon emissions, but it will come at the risk of electric reliability and related health and safety of

Michiganders.” *Id.* WPSC avers that the settlement agreement does not reflect the most reasonable and prudent path and that the Commission should “require Consumers to keep Campbell Unit 3 in operation, at least until Consumers can present hard data that verifies that Campbell Unit 3 can be retired without jeopardizing reliability and, as the PFD notes, Consumers has not modeled or analyzed these issues sufficiently.” *Id.*, p. 13.

13. Urban Core Collective

UCC filed a statement in support of the settlement agreement in lieu of an initial brief to reaffirm its initial support as a signatory to the settlement agreement. *See*, Case No. U-21090, filing #U-21090-0857.

D. Reply Briefs

1. Michigan Environmental Council, Natural Resources Defense Council, Inc., Sierra Club, and Citizens Utility Board of Michigan

In reply to Energy Michigan, MNS argues that Energy Michigan errs in positing that the considerations under MCL 460.6t(8) somehow trump the Rule 431 criteria. MNS’ reply brief, pp. 2-3. MNS notes that the Michigan Administrative Procedures Act (APA) also addresses settlements and provides that contested cases may end in settlement when agreed to by the parties in MCL 24.278(2). *Id.*, p. 3. MNS contends that Rule 431 implements this statutory requirement. While agreeing with Energy Michigan that it is important to harmonize the IRP statute and Rule 431, MNS contends that Energy Michigan’s reading of MCL 460.6t(8) would make applying the requirements of Rule 431 an “empty exercise.” *Id.*, p. 4. MNS further contends that Energy Michigan’s argument conflicts with the Commission’s approval of the contested settlement in Case No. U-20165. *Id.* (citing June 7, 2019 order in Case No. U-20165, p. 76 (June 7 order); *see also*, June 7 order, p. 91).

MNS states that it addressed Energy Michigan’s resource adequacy and pricing arguments in its initial brief, and notes that Energy Michigan was included in all settlement discussions, asserting that Energy Michigan was included in multiple emails regarding the settlement conference which took place in February 2022. MNS’ reply brief, p. 5.

In reply to WPSC, MNS again argues (as it did in its initial brief) that, contrary to WPSC’s assertions, the settlement agreement will actually improve resource adequacy in Zone 7. MNS again points to the 1,114 ZRCs from the Covert gas plant, 71 ZRCs of new battery storage, 250 ZRCs of new solar generation, and 94 ZRCs of new demand side resources, and states that “[e]ven with the retirement of the Campbell coal units, these resource additions will result in an overall net increase in Zone 7 resources.” *Id.*, p. 7 (citing 9 Tr 5-6, 10 Tr 4350, and Settlement Agreement, Sections 1-3); *see also*, 10 Tr 4405-4406. MNS further argues that WPSC’s repeated citations to the PFD for support are inapposite since the PFD evaluated the original PCA, which presented actual resource adequacy concerns. MNS’ reply brief, pp. 8-9.

MNS contends that the Commission should not consider the websites and news stories cited by WPSC regarding the PRMR because they are not part of the record, and, in any case, Mr. Jester, Mr. Proudfoot, and Mr. Clark rebutted these concerns. MNS’ reply brief, p. 10 (quoting 10 Tr 4406-4407) (citing 10 Tr 4358-4359 and 4227-4228). MNS notes that Mr. Proudfoot testified that:

The reserve margin used by the Company in its capacity demonstration for 2025 comes directly from the 2022-2023 MISO Loss of Load Expectation (LOLE) Study Report. It is also worth noting that assuming a constant reserve margin of 8.7% instead of 7.4% would represent about 100 MW of additional obligation to the Company. The differences between Karn Units 3 & 4 and the CMS capacity is still likely enough to cover this difference, even without counting any additional capacity from the one-time solicitation.

MNS' reply brief, p. 10 (quoting 10 Tr 4406-4407). MNS asserts that WPSC's claims about Consumers being capacity negative are simply untrue as shown by the list of ZRCs described above, and states that "Consumers would still have a surplus even if both tranches of the one-time solicitation fail entirely: in that extremely unlikely scenario, Consumers would still have a 514 ZRC surplus in 2025/26." MNS' reply brief, p. 11 (citing 10 Tr 4354). Finally, on this issue, MNS avers that Mr. Jester showed that Mr. King's calculations were incorrect because Mr. King assumed that Karn Units 3 and 4 would be operating in the 2025/2026 planning year. MNS' reply brief, p. 12 (citing 10 Tr 4355). MNS notes that WPSC fails to cite to any record evidence showing that the retirement of Campbell Unit 3 in 2025 is unsupported. MNS' reply brief, p. 12.

In reply to the BMPs, MNS argues that their claims regarding a lower ELCC are exaggerated and inaccurate, and states that the BMPs mischaracterized Mr. Clark's testimony where he indicated that the ELCC "could" drop. MNS' reply brief, p. 15 (citing 5 Tr 1123) (emphasis omitted). Additionally, MNS notes that several witnesses refuted this argument, including Mr. Clark himself when he testified that the ELCC has been stable for six years and no changes are pending. MNS' reply brief, pp. 15-16 (citing 10 Tr 4226-4227, 4236). MNS observes that Mr. Blumenstock testified that even applying the BMPs' 30% ELCC figure, there would be no shortfall for eight years. MNS' reply brief, p. 16 (citing 10 Tr 4142-4143). Additionally, MNS notes, Mr. Jester showed that the BMPs' figure comes from an exploratory modeling exercise. MNS' reply brief, p. 16 (citing 10 Tr 4365-4366).

Finally, MNS objects to the BMPs' appeal of certain evidentiary rulings made by the ALJ, noting that the BMPs fail to cite to any legal authority in support of their appeal. MNS argues that a party may not "simply announce a position on appeal and leave it to the reviewing body to search for authority to support the party's position." MNS' reply brief, p. 18 (citing *Wilson v*

Taylor, 457 Mich 232, 243; 577 NW2d 100 (1998)). MNS contends that the BMPs’ counsel misrepresented how long his cross-examination of Mr. Blumenstock would last, and then offered questions on irrelevant subjects. MNS’ reply brief, p. 18 (citing 10 Tr 4193, 4211). MNS contends that, under MCL 24.280(1)(d), the presiding officer is empowered to regulate the course of the proceedings. MNS avers that the ALJ’s rulings were reasonable and well within her authority and should be affirmed. MNS’ reply brief, pp. 18-19.

In reply to Mackinac, MNS urges the Commission to give no weight to Mackinac’s brief. As an initial matter, MNS alleges that Mackinac did not comply with the requirements of Rule 431(3) when it filed its objection, because it failed to state its objections with particularity or specify how it would be adversely affected by the settlement agreement. Additionally, MNS argues, Mackinac’s initial brief is mostly cut-and-pasted from its exceptions, and the exceptions were focused on the PFD and the original PCA – a different factual scenario. MNS notes that Mackinac’s initial brief is filled with unsupported assertions and relies heavily on news stories and website links that are not part of the record, contrary to the requirements of the APA. MNS’ reply brief, pp. 20-21 (citing MCL 24.276 and 24.285). Moreover, MNS posits, DR and CVR programs are not designed to cut off customers from electricity. MNS describes Mackinac as “ill-informed.” MNS’ reply brief, pp. 21-22.

2. The Commission Staff

In reply, the Staff states that MCL 460.6t(8) provides seven factors for the Commission to balance when determining if the statutory requirements are satisfied. The Staff states that the settlement agreement is a compromise made by parties with a wide variety of interests and is reasonable and prudent. The Staff also contends that “the settlement agreement also balances the

reliability needs of MISO Zone 7 with Consumers’ ability to provide energy and capacity to its customers.” Staff’s reply brief, p. 2 (citing Staff’s initial brief, pp. 3-5).

Regarding resource adequacy concerns, the Staff replies that the PCA, as modified by the settlement agreement, is reasonable and prudent and balances the reliability needs of Zone 7. *See*, Staff’s reply brief, p. 3. Continuing, the Staff avers that “[g]iven the capacity from Karn Units 3 and 4, additional solar resources, and the up to 700 MW one-time solicitation set forth in the settlement agreement, Staff . . . does not believe Consumers is likely to be short on capacity in 2025” and that “this capacity is more than sufficient to make up the capacity assumed for the CMS [plants] contemplated in Consumers’ original IRP and may even be sufficient to meet Consumers’ previous planning reserve margin of 8.7% that [WPSC] referenced in direct testimony.” *Id.*, pp. 3 4 (citing 10 Tr 4306, 4406-4407).

In response to the BMPs’ testimony regarding a deficiency in 2035, the Staff replies:

that the IRP statute requires 5-, 10-, and 15-year projections of the utility’s load obligation and plan, but Commission cost approval for investments or resources used to meet energy and capacity need is only presumed reasonable and prudent for those actions commenced within three years of Commission approval of the IRP. MCL 460.6t(3), (11).

Staff’s reply brief, p. 4. Therefore, the Staff avers that there is a likelihood that changes will occur between the approval of the IRP and the long-term projections as further reinforced by the requirement in MCL 460.6t(20) for regulated utilities make an IRP filing at least every 5 years. *Id.*

Finally, the Staff avers that Mackinac’s “initial brief contains many footnotes citing to material that was not offered into evidence or addressed in testimony” and that Mackinac “did not file testimony in either phase of this proceeding and filed a one-page objection to the settlement agreement.” *Id.*, p. 6. Therefore, the Staff requests that the Commission disregard the portions of

Mackinac's briefing supporting its objections to the settlement agreement not supported on the record.

3. Environmental Law and Policy Center of the Midwest, Ecology Center, Inc., Union of Concerned Scientists, Inc., and Vote Solar

In reply to the BMPs, the CEOs point out that the BMPs' request to modify the settlement agreement is a form of relief that is unavailable because the settlement agreement is not severable, thus modification would result in rejection of the entire agreement. CEOs' reply brief, p. 1, n. 1. The CEOs further aver that the BMPs' contracts should not be extended in any case due to the non-carbon pollution associated with their operations as well as the documented environmental justice concerns. CEOs' reply brief, p. 2. The CEOs note that one of the directives issued by Governor Whitmer pursuant to ED 2020-10 requires the Michigan Department of Environment, Great Lakes, and Energy to include considerations of environmental justice and public health when issuing advisory opinions in IRP proceedings. *Id.*, pp. 2-3. The CEOs submit that they provided extensive evidence on the record showing the non-carbon air pollution emissions and environmental justice concerns associated with the BMPs, stating that:

[s]ome of these plants co-fire tire-derived fuels, and most of them have higher emission rates of PM_{2.5} and NO_x than even Consumers' coal plants. (Krieger, 7 TR 2383). Moreover, eight of nine plants are located in areas considered more low-income than the state median. (Krieger, 7 TR 2383). The 38,000 people living near the Genesee plant rank in the 89th percentile for low-income populations, 86th percentile for populations of color, and 83rd percentile on the EJ [Environmental Justice] Index. (Krieger, 7 TR 2384). "[B]iomass power plants are likely to have higher air pollutant emissions rates per unit energy produced."

CEOs' reply brief, p. 3 (quoting 7 Tr 2397) (emphasis omitted). The CEOs note that Dr. Bilsback concluded that the emissions rates of biomass plants are comparable to fossil-fuel fired plants. CEOs' reply brief, p. 4 (citing 7 Tr 2418). The CEOs contend that simply because a fuel source

may be renewable does not mean that it will not have health impacts; and they note that the BMPs did not rebut this testimony. CEOs' reply brief, p. 4.

The CEOs also regard the BMPs' argument that the settlement agreement is a ploy to allow for the construction of a natural gas plant as far-fetched. The CEOs point out that the settlement agreement (Section 6.b.ii.) limits the second tranche to "intermittent resources and dispatchable, nonintermittent clean capacity resources (including battery storage resources)," which could not be reasonably interpreted to include natural gas. *Id.* (quoting Settlement Agreement, p. 6). The CEOs further note that they would not be signatories to a settlement agreement that contemplates the construction of a new gas plant. CEOs' reply brief, p. 5 (citing 7 Tr 2354 and 10 Tr 4347). The CEOs contend that the land use concerns raised by the BMPs do not appear to relate to ED 2020-10. CEOs' reply brief, pp. 5-6.

The CEOs further argue that WPSC and the BMPs attempt to use scare tactics based on market information. The CEOs assert that Consumers used an appropriate capacity factor in its modeling, stating that, in reference to the BMPs' evidence, "[a]s Company witness Battaglia explained on rebuttal, the information shown in BMP-6 is presented in DC, rather than AC, and therefore does not present a comparable capacity factor to that used by the Company in modeling. (Battaglia Direct, 5 TR 1217:4-12)." CEOs' reply brief, p. 7. The CEOs also note that the BMPs focused on the wrong witness with respect to their ELCC arguments, as the solar capacity factor was covered by Mr. Kapala and not Mr. Battaglia (and this mistake was noted by the ALJ as well). *Id.*, p. 8 (citing 6 Tr 1296-1297; 7 Tr 1822). The CEOs further assert that WPSC's theory that Consumers will be unable to acquire 250 ZRCs of solar by 2025 was refuted by Mr. Lucas. CEOs' reply brief, p. 9 (citing 10 Tr 4382-4384). They also cite to the testimony of Mr. Clark and Mr. Jester refuting the notion that the ELCC poses an unreasonable risk to the settlement

agreement. CEOs' reply brief, p. 9 (citing 10 Tr 4236, 4367-4368). Finally, the CEOs point to Mr. Blumenstock's testimony that Karn Units 3 and 4 are unlikely to become system support resources. CEOs' reply brief, p. 10 (citing 10 Tr 4152).

The CEOs assert that Mackinac's arguments are improper and redundant. CEOs' reply brief, p. 10.

4. Consumers Energy Company

Consumers initially provides an overview of the arguments of the signatories to the settlement agreement reiterating its position that the settlement agreement is in the public interest, was the result of good-faith negotiation, and that the outcome is the most reasonable and prudent means of meeting the company's energy and capacity needs. Consumers' reply brief, pp. 3-5.

Consumers argues that issues raised by WPSC with regard to reliability and resource adequacy concerns have been addressed by the company's initial brief. Specifically, Consumers states that "[WPSC]'s claim . . . that the one-time solicitation will likely not create new [MISO LRZ] 7 capacity, is of no consequence" for the reasons set forth in its initial brief. *Id.*, p. 6. Consumers argues that "[t]he purpose of the one-time solicitation is to help replace the capacity and energy lost when Consumers Energy retires [Campbell] Units 1, 2, and 3 in 2025." *Id.* Consumers repeats that "[t]he Company is not required to provide capacity for [WPSC] or any other [LSEs] in LRZ 7." *Id.* Consumers states that WPSC's arguments that the settlement agreement will reduce reliability in LRZ 7 are "without merit" as outlined in its initial brief and WPSC has "failed to provide information showing any purported negative impact on [WPSC]" *Id.*, p. 7. Consumers reiterates that the settlement agreement will "bring at least 2,084 ZRCs into MISO's LRZ 7 and retire only approximately 1,400 ZRCs of capacity, with a net addition for LRZ 7 of nearly 700 ZRCs." *Id.* (footnote omitted). In response to WPSC's claims that the company's

PRMR will increase rather than decrease, Consumers argues that it has “fully supported its projected PRMR decrease” in its initial brief. *Id.* Consumers argues that WPSC’s claims that the one-time solicitation is “speculative and not supported by the record” are “meritless” and “Consumers Energy projects sufficient capacity for planning year 2025-2026, even without the additional 700 ZRCs of capacity proposed to be acquired via the solicitation, and many possible sources could fill the 700 ZRCs once the bidding commences.” *Id.*, p. 8 (quoting WPSC’s initial brief, p. 9).

Consumers addresses WPSC’s claim that the settlement agreement would “treat Consumers Energy as an ‘island,’ and that a capacity shortfall would affect [WPSC] and other LSEs in the state.” Consumers reply brief, p. 8 (quoting WPSC’s initial brief, p. 10). Consumers asserts that:

Michigan law contemplates that each electric provider plan to serve its own projected loads; it does not require electric providers to serve other electric providers’ loads, unless a utility is required to provide backup capacity under the state reliability mechanism in situations in which alternative electric suppliers fail to demonstrate compliance with their own four-year forward capacity obligations.

Consumers reply brief, p. 8 (citing MCL 460.6w). Consumers discredits WPSC’s claims that the record does not support the settlement agreement. *See*, Consumers’ reply brief, p. 9.

Turning to Energy Michigan’s arguments, Consumers first agrees with Energy Michigan’s contention that “the Commission Rule 431 standards for approving a contested settlement must harmonize with Section 6t(8) [of Act 341], and cannot overrule it or provide a ‘different and weaker approval standard.’” Consumers reply brief, p. 9 (quoting Energy Michigan’s initial brief, p. 2). Consumers posits that the settlement agreement “meets all criteria for approval contained in MCL 460.6t(8) and Commission Rule 431.” Consumers reply brief, p. 9.

Consumers addresses Energy Michigan’s assertion that company testimony stating “that ‘Consumers Energy is not responsible to ensure the reliability of Zone 7 beyond its own capacity

obligations’ indicates that the Company has changed its position, given that Mr. Clark described the IRP as the best plan ‘for Michigan.’” *Id.*, p. 10 (quoting Energy Michigan’s initial brief, p. 3).

Consumers asserts that it has not changed its position. Specifically, Consumers states that:

The IRP, as set forth in the Settlement Agreement, remains the best plan for Michigan, as it will meet its customers’ energy needs, will satisfy the Company’s PRMR obligations within LRZ 7, and further the Company’s goal to be carbon neutral by 2040 and retire all coal generation by 2025. Having the best plan for Michigan does not mean that Consumers Energy must single-handedly supply sufficient capacity for every other utility’s expected load in Michigan. It means having a plan that meets all of Consumers Energy’s customers’ capacity needs in a manner that avoids unnecessary environmental impacts that affect the whole state and benefits the state’s economy positively. An IRP that accomplishes these objectives is best for Michigan.

Consumers’ reply brief, p. 10.

Consumers replies to Energy Michigan’s claim that the one-time solicitation might ultimately lead to PPAs with CMS Enterprises. *Id.* Consumers responds that “[t]he Company has not yet issued the solicitation, thus Energy Michigan is merely speculating which resources will win.” *Id.* Consumers avers that “even in the scenario that Energy Michigan envisions, no adverse impact on resource reliability or adequacy would result.” *Id.*

Consumers refutes Energy Michigan’s claim “that it was never invited to a settlement meeting, that its comments on the draft settlement agreement were neither welcomed nor considered,” and that Energy Michigan was explicitly told that no changes it sent the company would be considered. *Id.*, p. 11. Consumers posits that “[a] settlement meeting was held with all parties on February 16, 2022, and Energy Michigan’s counsel participated in that meeting. Energy Michigan did not engage in settlement discussions after that meeting, even though such engagement was encouraged by the Company.” *Id.* Further, Consumers states that “[b]eyond the February 16, 2022 settlement meeting, Energy Michigan was also engaged by the Company

regarding settlement on numerous occasions including March 28, 2022, April 15, 2022, and April 19, 2022.” *Id.*, pp. 11-12.

Consumers avers that “Energy Michigan’s assertions regarding the settlement process is irrelevant and beyond the scope of this case” as “other potential settlement outcomes are not within the scope of issues to be decided by the Commission in a contested settlement proceeding” *Id.*, p. 12 (citing June 7, 2019 order in Case No. U-20165). Consumers also posits that the “[Commission]’s Rules of Practice and Procedure make clear that reaching a total consensus is not required for settlement.” Consumers’ reply brief, p. 12. Consumers adds that “Rule 431 makes clear that a settlement may be ‘proposed by some of the parties.’” *Id.* (quoting Mich Admin Code, R 792.10431(3)). Further, Consumers quotes Rule 431 as stating that “‘provisions of these rules shall not be construed in any way to prohibit settlements.’” Consumers’ reply brief, pp. 12-13 (quoting Mich Admin Code, R 792.10431(3)).

Turning to the claims of the BMPs, Consumers argues that “even though the BMPs are claiming that the Settlement Agreement is flawed, they are at the same time conceding that all of those purported flaws melt away if the BMPs just get what they want—to amend the Settlement Agreement to force Consumers Energy to extend PPAs with its member plants.” Consumers’ reply brief, p. 14. Consumers posits that “[t]he BMPs’ position illuminates the fact that there are not really flaws in the Settlement Agreement, as the BMPs’ [sic] claim, and that the BMPs’ position merely seeks to promote their own economic interests.” *Id.* Further, Consumers avers that the BMPs have not established that their member plants are an economic and reasonable option for Consumers’ customers following the expiration of the current PPAs for those plants. *Id.* Consumers further reiterates its positions from brief that the company does not have an obligation to enter into new contracts with the BMPs, that the BMPs were considered in the development of

the IRP, and that the BMPs have not produced evidence that they represent a viable economic option. *Id.* Consumers asserts that the BMPs’ alternative proposal under Section 6t(6) of Act 341 is not supported because “the BMPs have failed to address and meet the filing requirements for an alternative proposal, as provided in the Certificate of Necessity and Integrated Resource Plan Alternative Filing Requirements.” Consumers’ reply brief, p. 15 (citing December 20, 2017 order in Case No. U-18461, Exhibit B). Consumers opines that the BMPs requested relief should be rejected because “[t]he BMPs have not established that their member plants will be an economic and reasonable resource option for customers and therefore, there is no basis to support the BMPs’ request to force the Company to extend PPAs with those plants.” Consumers’ reply brief, p. 16.

In response to the BMPs’ claims that the settlement agreement fails to meet the resource adequacy and reliability requirements of Sections 6t(8)(a)(i) and (iv) of Act 341, Consumers asserts that “[t]he Settlement Agreement ensures resource adequacy and capacity that is sufficient in quantity to serve anticipated peak electric load plus applicable PRMR and Local Clearing Requirement” Consumers’ reply brief, p. 17. Consumers argues that the settlement agreement has “maintained a balance of resource additions and retirements—backfilling capacity lost to accelerated retirement with the addition of new baseload resources, expansion of demand-response resources, expansion of renewable resources, and deployment of battery storage resources.” *Id.* (citing 10 Tr 4121). Consumers also reiterated that the settlement agreement provides mechanisms to procure additional capacity if needed. Consumers’ reply brief, p. 17. Consumers posits that the settlement agreement provides for “electric reliability assurance” and that the “flexibility of phased-in modular resources provided for in the Settlement Agreement PCA also provides the Company adequate time to mitigate cost, assess reliability within the reconfigured portfolio, and to modify as necessary.” *Id.*, p. 18.

Consumers contests the BMPs' claim that the company used an incorrect capacity accreditation for its solar resources. Consumers restates that the company's PCA "uses the current MISO solar capacity accreditation practices which provide solar with a 50% capacity accreditation." *Id.* (citing 10 Tr 4142). Consumers reiterates its arguments that "that MISO solar capacity accreditation value is also only relevant to newly installed solar and not solar that is in actual operation. Capacity accreditation at the Company's existing solar facilities has been as high as 65%, based on actual performance." Consumers' reply brief, p. 19 (citing 10 Tr 4142). Consumers argues that the company has supported its modeled capacity factor for solar with projections from third-party resources. Consumers' reply brief, p. 19. Thus, Consumers opines that the BMPs' resource adequacy and reliability arguments should be rejected. *Id.*

Responding to the BMPs' claims that the settlement agreement fails to meet the requirements of Section 6t(8)(b) of Act 341 and Governor Gretchen Whitmer's MI Healthy Climate Plan pursuant to ED 2020-10, Consumers argues that "the record establishes that the Settlement Agreement is aligned with that plan, and will help promote its success." Consumers' reply brief, p. 20. Consumers adds that to the extent the BMPs are arguing that additional imports from the market violate ED 2020-10, the PCA, as modified by the settlement agreement, "reduced the need for market purchases" and "continues to maintain that reduced market dependence through the purchase of the Covert Plant and one-time solicitation" *Id.*

Addressing the BMPs' assertion that Karn Units 3 and 4 could be designated as an SSR, Consumers reiterates that "an SSR designation would result from an electric transmission system deficiency that must be mitigated and not due to a capacity or energy shortfall." *Id.*, p. 21. Reiterating its earlier testimony, Consumers argues that the risk of an SSR designation is unsupported. *Id.*, pp. 20-21.

In response to the BMPs’ assertion that the settlement agreement fails to appropriately balance the diversity of generation resources with the impacts on commodity price risk, Consumers asserts that the settlement agreement provides for a diverse portfolio of resources as outlined in its testimony. *Id.*, p. 21. Consumers posits that “[t]his resource mix represents a balanced and modular supply plan which provides flexibility to adjust to changes in fuel costs, technology cost, electric demand, or the business environment and insulates the Company and its customers from commodity price risks.” *Id.* Further, Consumers asserts that this approach will “provide further opportunities for the utilization of diverse supply resources and protects against high customer rates.” *Id.*

Consumers reiterates its arguments, outlined above, regarding the scope of the contested settlement agreement in response to the BMPs. *See, id.*, pp. 23-26. Consumers reasserts that the BMPs attempt to propose another version of the settlement agreement is “improper and not supported.” Consumers’ reply brief, p. 25. On pages 26 through 33 of its reply brief, Consumers addresses the BMPs’ appeal of the ALJ’s rulings.

Consumers asserts that Mackinac’s objections to the settlement failed to comport with the Commission’s procedural rules and should thus be disregarded. *Id.*, pp. 32-33.

Consumers requests the Commission approve the settlement agreement in its entirety without any modifications or conditions. *Id.*, p. 33.

5. Wolverine Power Supply Cooperative

WPSC argues that the settlement agreement “has neither the facts nor the law on its side and the Commission must reject it.” WPSC’s reply brief, p. 1. WPSC contends that the Staff has reversed its stance on the importance of resource adequacy as the Staff now contends that the settlement agreement “should be approved because Zonal resource adequacy is not Consumers’

problem to solve.” WPSC’s reply brief, p. 3 (citing Staff’s initial brief, p. 5). WPSC avers that while it is not the sole responsibility of Consumers to “ensure resource adequacy for the Zone, a significant component of the IRP framework is to ensure that a utility retiring resources does not do so in a manner that adversely impacts the Zone, which Consumers does here” and that “although Consumers may not be required to address a shortfall caused by others, it certainly must be required to address a shortfall it is creating.” *Id.* (emphasis omitted).

WPSC again avers that the settlement agreement is not supported by substantial evidence and that the company has not disputed the negative ZRC values for 2022-2023 and 2025-2026. *See, id.*, p. 4. WPSC reiterates concerns regarding the ELCC for solar assets, arguing that the 50% is not an accurate benchmark as “[i]t simply does not reflect reality, even if some are willing to pretend that it does.” *Id.* WPSC further states that it has “identified actual impediments to Consumers’ contemplated solar development and Consumers offered no explanation as to how it will overcome these hurdles, except to say there is time to address in future IRPs. [WPSC] identified the issues; Consumers identified no solutions.” *Id.*, p. 5.

Finally, WPSC argues that the Staff’s briefing lacks confidence “[m]uch like Consumers’ failure to explain its solution to the hurdles related to solar development, Staff appears to be counting on speculative ‘other resources’ that are not identified in brief or the record.” *Id.* Therefore, WPSC avers that the settlement agreement is speculative and should be denied under Rule 431(5).

6. The Biomass Merchant Plants

In reply to Consumers, the BMPs reference their initial brief to respond to the claim that the BMPs’ “requested relief is beyond the scope of these proceedings” averring that “[i]t is not.” BMPs’ reply brief, p. 2. The BMPs reiterate that while “PURPA may no longer require

Consumers to purchase generation from the Biomass Plants [that] does not mean that such purchases are not reasonable and prudent as a matter of state law” and that Consumers has done everything possible “to exclude the Biomass Plants from the IRP, regardless of whether or not including them would be reasonable and prudent.” *Id.* (citing to BMPs’ initial brief, p. 29-38). Reiterating the testimony and briefing, the BMPs state that the company never requested cost information from the BMPs and failed to explain why the cost of new construction was utilized for biomass generation. *See*, BMPs’ reply brief, pp. 2-4.

Responding to Consumers’ contention that the BMPs would be eligible to bid into the first tranche of the one-time solicitation, the BMPs aver that:

[w]hile the Biomass Plants can be dispatched within their operational limits, they cannot be dispatched within one hour if they are not running. That fact, in addition to the fact that all of the Biomass Plants’ current contracts extend into the 2025 to 2030 time period will exclude them from bidding in that solicitation.

Id., p. 4 (referencing Consumers’ initial brief, p. 45). The BMPs again reference objections and excluded evidence which they aver were inappropriately ruled upon by the ALJ. The BMPs aver that Consumers failed to discuss “whether [Consumers] is likely to sign power purchase agreements with [the CMS plants] as a result of the first tranche of the One Time Solicitation, which is probable.” *Id.*, pp. 5-6. Further, the BMPs restate record testimony to aver that Consumers has still failed to rebut the BMPs’ testimony regarding the overstated solar capacity factor the company has utilized, and the risk associated with proposed solar additions. *See, id.*, pp. 6-10. The BMPs argue that Consumers’ dismissal of the risks relating to the solar additions, and “its refusal to add the 188 MW of baseload, net zero carbon, renewable generation from the Biomass Plants to its IRP” are invalid and raise “serious questions as to whether the Biomass Plants are being excluded from the IRP for some other undisclosed commercial reason.” *Id.*, pp. 10-11.

V. Discussion

The Commission finds that the contested settlement agreement at issue in this case should be approved.

As stated above, Commission approval of a contested settlement agreement is appropriate where the Commission determines the following requirements have been met: (1) that the objecting parties have been given a reasonable opportunity to present evidence and arguments in opposition to the settlement agreement, (2) the public interest is adequately represented by the parties who entered into the settlement agreement, (3) the settlement agreement is in the public interest, (4) the settlement agreement represents a fair and reasonable resolution of the proceeding, and (5) the settlement agreement is supported by substantial evidence on the record as a whole. Mich Admin Code, R 792.10431.

The Commission finds that all the requirements of Rule 431 have been met. The Commission has provided a reasonable opportunity to those parties that objected to the settlement agreement to present evidence and argument in opposition to the settlement agreement. The parties were given the opportunity to submit direct and rebuttal testimony, file initial and reply briefs, and appear at an evidentiary hearing regarding the contested settlement agreement before a presiding officer. As the parties to this case observed, the principal record in this case consists of 4,094 pages of transcript and over 500 exhibits admitted into evidence. The record on the contested settlement alone consists of 315 additional pages of transcript and 22 additional exhibits admitted into evidence.

With respect to the second criterion, the record shows that the signatories to the settlement agreement represent a broad cross-section of interests, including residential customers, commercial and industrial customers, businesses in Michigan's advanced energy sector, environmental groups,

a transmission company, and third-party developers. *See*, 10 Tr 4407-4408. The Commission also notes that the Court of Appeals has affirmed the Commission's determination that the public interest is adequately represented by the Staff when the Staff is party to a contested settlement agreement. *Attorney General v Mich Pub Serv Comm*, 237 Mich App 82, 93-94; 602 NW2d 225 (1999). Accordingly, the Commission finds that the public interest is adequately represented by the parties who entered into the settlement agreement.

Rule 431(5)(c) requires the Commission to make a three-part finding that: (1) the settlement agreement is in the public interest, (2) represents a fair and reasonable resolution of the proceeding, and (3) is supported by substantial evidence on the record as a whole.

The Commission finds that the settlement agreement is in the public interest. The Commission finds persuasive the testimony by Consumers and others that the settlement agreement was the result of good-faith negotiation that resulted in significant compromises for all involved. The negotiation of the parties is evident when comparing the details of Consumers' initial IRP filing with the terms of the proposed settlement agreement. Signatory parties to this case highlighted the following provisions as compromises reached by settlement that are in the public interest, represent a fair and reasonable resolution of the proceeding, and are supported by substantial evidence on the record as a whole:

- The agreement that Consumers retire Campbell Units 1, 2, and 3 in 2025, which will result in savings to ratepayers, reduce the production of environmental pollutants, such as SO₂, NO_x, and particulate matter, and advance Michigan's clean energy goals as outlined in the MI Healthy Climate Plan as well as provide additional public health benefits;

- The agreement that Consumers will purchase the Covert plant in 2023, which will add 1,114 ZRCs to MISO Zone 7 to support reliability for Consumers as well as overall resource adequacy of the Zone;
- The agreement to conduct a one-time solicitation for 200 ZRCs of capacity and associated energy and RECs, which will provide additional clean capacity resources for Consumers' portfolio;
- The agreement that Consumers will deploy the battery program outlined in the rebuttal testimony in the principal case which will formalize an important component of a cleaner energy grid while enhancing reliability and resource adequacy;
- The agreement to seek recovery of the unrecovered book value and decommissioning costs of retiring coal units through regulatory asset treatment, rather than continued recovery through traditional ratemaking, which provides the potential for customer savings;
- The agreement that Consumers will donate \$5 million dollars in shareholder funds to support bill assistance for lower-income customers along with continued annual donations;
- The agreement that Consumers will provide beneficial modeling in its next IRP, including total emissions, annual particulate matter health impacts, an environmental justice screening tool, projected low-income energy efficiency participation levels, publicly available rooftop solar adoption rates, and transmission import analysis; and
- The agreement that Consumers will take steps to engage and gather input from the public prior to the filing of its next IRP with the Commission, which will ensure that additional information and perspectives are available to inform both the company's assessment of its future resource options as well as Commission and stakeholder review of its proposals.

Energy Michigan, WPSC, the BMPs, and Mackinac disagree with the conclusion that the settlement is in the public interest and represents a reasonable resolution to the proceeding. The objecting parties' concerns involve the resource adequacy, reliability, and competitive pricing in MISO Zone 7. Specifically, the objecting parties argue that: (1) the settlement agreement does not meet the resource adequacy needs of MISO Zone 7 and (2) the one-time competitive solicitation will not adequately replace the capacity from retiring coal-fired generation. Each of these concerns are addressed in turn.

A. The Resource Adequacy of Zone 7

The parties objecting to the settlement agreement claim that the settlement agreement does not address the need for incremental capacity replacements in MISO Zone 7 following the retirement of Campbell Units 1, 2, and 3 to meet the resource adequacy requirements of the zone. As such, the objecting parties conclude that Consumers' PCA fails to meet the resource adequacy requirements of Section 6t(8)(a)(i) and (iv) that the Commission must balance "[r]esource adequacy and capacity to serve anticipated peak electric load, applicable planning reserve margin, and local clearing requirement" and "reliability" to determine that the integrated resource plan is the most reasonable and prudent means of meeting energy and capacity needs. The Commission disagrees.

The Commission finds the testimony of the Staff, MNS, and Consumers compelling. As Consumers testifies, the settlement agreement continues the annual solicitation process adopted by the company in its 2018 IRP. 10 Tr 4121. By preserving the solar ramp-up proposed in the original PCA, the settlement agreement adds 250 ZRCs of new solar generation by the 2025/2026 PY, increasing to 852 ZRCs by the 2028/2029 PY. 10 Tr 4350. The settlement agreement provides that Consumers will deploy a new utility-scale battery storage program which will add

approximately 71 ZRCs of new capacity to the zone. 10 Tr 4350. Finally, preserving the EWR and DR provisions from Consumers’ original PCA, the settlement provides 94 ZRCs of demand-side resources by the 2025/2026 PY, increasing to 2031 ZRCs by the 2028/2029 PY. The settlement also provides for increases in both the demand-side resources and solar resources in later years. 10 Tr 4350.

In addition to these new resources, the settlement agreement provides for the acquisition of the Covert plant, which will transfer approximately 1,114 ZRCs from PJM into MISO Zone 7. 10 Tr 4123, 4225, 4230, 4331. The settlement agreement has the effect of adding approximately 770 ZRCs through the continued operation of Karn Units 3 and 4 until May 31, 2031, consistent with the design lives of those units. 10 Tr 4225, 4334.

MNS provides that “the settlement [agreement] will result in a projected net increase of at least 127 ZRCs. By 2028/29, the projected net increase will be at least 923 ZRCs.” 10 Tr 4350. The Staff further contends that, “[t]he Company was originally proposing to retire approximately 2800 MW (nameplate) generation from MISO Zone 7 . . . ,” meanwhile the settlement agreement “only retires a portion of that amount, approximately 1500 MW” 10 Tr 4405. The projections by both MNS and the Staff are in addition to any resources that may be acquired through the one-time solicitation, discussed below. 10 Tr 4351-4352, 4406. As Consumers observes, the settlement agreement provides for more capacity in Zone 7 than was included in the company’s originally filed PCA. 10 Tr 4230. The Commission thus finds that the settlement agreement provides a reasonable and prudent plan for meeting resource adequacy requirements.

The Commission acknowledges the larger resource adequacy concerns of the objecting parties as valid and timely. The broader resource adequacy of Zone 7 and the MISO region has an impact on both Consumers’ customers and the state as a whole. The Commission observes that the

2022/2023 MISO PRA results indicate a capacity shortfall for the MISO North and Central Regions.⁵ These auction results indicate that many LSEs in MISO will experience a greater risk of implementing involuntary conservation measures even though many of them would appear to be resource adequate when viewed as a stand-alone entity. While the market construct within MISO allows for the pooling of resources to lower the total cost to customers, this market construct means that the planned retirements and resource decisions of one utility impact the customers of other utilities within the Zone and the greater regional transmission organization (RTO).

While the Commission agrees with Consumers' assertion that the company is not responsible for the reliability of the entirety of MISO Zone 7, it is also clear that a deficiency in any part of Zone 7 would increase the likelihood of grid outages for all customers in Zone 7, including those served by Consumers.

As noted above, however, the approval of the settlement agreement enhances zonal resource adequacy in the short, medium, and long term(s). In the short term, the acquisition of the Covert plant will transfer approximately 1,114 ZRCs from PJM into MISO, providing much needed additional capacity to LRZ 7 for the next MISO PY. In the long term, as noted by Mr. Jester, "[c]ontinuing to operate Karn 3-4 supports Consumers' attainment of planning reserve margin requirements by maintaining more than 780 ZRCs in the Company's portfolio." 10 Tr 4334. And as the Staff noted, the settlement agreement represents "a resource adequacy improvement over the Company's original PCA[,] and provides for approximately 400 ZRCs of new resources within

⁵ The resources in the MISO region operate as a shared pool of resources to meet the PRMR. As demonstrated in the MISO 2022/2023 PRA results, capacity shortfalls in four MISO Zones resulted in the entirety of the MISO North/Central Regions having a slightly increased risk of needing to implement temporary controlled load sheds. The 2022/2023 PRA results are available at: <https://cdn.misoenergy.org/2022%20PRA%20Results624053.pdf> (accessed, June 17, 2022).

MISO Zone 7 by 2025, in addition to the one-time solicitation for 700 MW set forth in the settlement agreement. 10 Tr 4405, 4406. Finally, while acknowledging the challenges to resource adequacy that were highlighted in MISO's recent PRA results, the Commission notes Consumers' testimony that it "will file at least one, if not multiple, IRPs" between now and when any projected shortfalls are likely to occur, and that it will have "ample time to respond and adjust the PCA" if necessary. 10 Tr 4143-4144. As such, the Commission is satisfied that the approval of the settlement agreement will enhance resource adequacy in Zone 7 in both the near-term and long-term.

In order to ensure future IRPs appropriately consider zonal resource adequacy in addition to the resource requirements of a particular utility, the Commission directs the Staff to include a requirement for each utility to consider the impacts of its PCA on the resource adequacy of its own customers, the LRZ in MISO or its equivalent in PJM, and also assess the potential impacts, if any, of its decisions on customers in neighboring Zones, regions, or RTOs in the upcoming IRP filing requirements update in Case No. U-18461 in order to better enable the Commission to determine whether future PCAs meet resource adequacy needs of the LRZ.

B. The One-Time Solicitation

The parties objecting to the settlement agreement also express concerns regarding the one-time solicitation as it is outlined in the settlement agreement. Among the concerns, Energy Michigan asserts that the 500 ZRC capacity need that Consumers is seeking to fill through the first tranche of the one-time solicitation will result in capacity that is not additional to what is already being counted toward MISO Zone 7's resource adequacy requirements. 10 Tr 4297. The BMPs and WPSC express concerns that the timing and framing of the one-time solicitation will not result in new resources being added to the market. Specifically, these two parties assert that it will not

be possible for new generation to obtain a MISO Interconnection Services Agreement, complete project engineering, obtain financing, and construct a new plant by 2025, as the settlement agreement requires the generation to provide Consumers with a capacity credit in MISO Zone 7 by 2025. The Commission finds that this reasoning for denying the settlement agreement is speculative. As several parties contended, the terms of the settlement agreement require that the resources acquired be competitively sourced. The Commission finds persuasive testimony that “respondents to the solicitation could be from some of the projects currently in the MISO queue . . . that makes up nearly 1,800 MW of projects that are currently in Study Phase 2 or 3.” 10 Tr 4404 (footnote omitted). And further that “there are more than 13,011 MWs of solar, battery, and solar/battery hybrid projects located in MISO Zone 7 that have an application in-service date by or before June 1, 2025 Of these projects, 5,365 MW of solar, 499 MW of solar/battery hybrid, and 370 MW of battery have completed Phase 2 or Phase 3 interconnection studies and are therefore highly likely to proceed if the developer has an offtake or build-transfer agreement.” 10 Tr 4363-4364 (footnotes omitted). The Commission finds that the one-time solicitation is in the public interest as it is likely to contribute to—or at a minimum not be detrimental to—the overall resource adequacy of MISO Zone 7.

However, to clarify, the Commission does not interpret the language of the settlement agreement to mean that it is pre-judging any approval requests it may receive from Consumers as a result of this one-time solicitation or any other approval requests that Consumers may file following the implementation of its PCA. The language of the settlement reads:

[T]he actual selected bid(s) will be submitted in Case No. U-21090 for Commission approval subsequent to the completion of the One-Time Solicitation;

In that approval proceeding, the Commission shall: (i) confirm whether the solicitation process followed by the Company is consistent with the requirements of the Settlement Agreement; (ii) grant approval of the recovery

of the costs associated with the selected project(s) pursuant to applicable law or make a preliminary finding that the costs associated with the project(s) that prevail in the solicitation are reasonable and prudent; and (iii) grant any other approvals or findings necessary as required or provided by applicable law.

Settlement Agreement, pp. 6-7. As such, the Commission will examine the results of the one-time solicitation carefully and will scrutinize any effects it may have on resource adequacy and competitive pricing in Zone 7.

Having addressed each of the arguments as to whether the settlement agreement is in the public interest and represents a fair and reasonable resolution of the proceeding, the Commission finds that, for all the reasons set forth, the settlement agreement is in the public interest. The Commission also finds that the proposed settlement agreement is a fair and reasonable resolution of this proceeding. In addition, having read the record, the Commission likewise finds the settlement agreement to be supported by substantial evidence on the record as a whole. Moreover, as agreed to by the parties in paragraph 1 of the settlement agreement and supported by the record, the Commission finds that Consumers' PCA as amended by the settlement agreement is the most reasonable and prudent means of meeting Consumers' energy and capacity needs and otherwise meets the requirements of MCL 460.6t(8).

THEREFORE, IT IS ORDERED that:

- A. The settlement agreement, attached as Exhibit A, is approved.
- B. Unless otherwise provided in the settlement agreement, the terms of the approved settlement agreement shall take effect immediately upon issuance of this order.
- C. The Commission Staff shall include a requirement for each affected utility to consider the impacts of its proposed course of action on the resource adequacy of its own customers, the Midcontinent Independent System Operator, Inc. Local Resource Zone or respective PJM

Interconnection, L.L.C. Zone, and neighboring Zones, regions, or regional transmission organizations in the updated integrated resource plan filing requirements to be filed on June 30, 2022, in Case No. U-18461, as outlined in this order.

D. In accordance with paragraph 11(g) of the settlement agreement, Consumers Energy Company shall file, within 30 days of this order, revised Standard Offer tariff sheets and a revised Standard Offer contract, to reflect the Standard Offer construct and rates approved as part of the approved settlement agreement. Also pursuant to paragraph 11(g), parties shall have 14 calendar days subsequent to these filings to provide comments to the Commission in this docket.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, under MCL 462.26. To comply with the Michigan Rules of Court's requirement to notify the Commission of an appeal, appellants shall send required notices to both the Commission's Executive Secretary and to the Commission's Legal Counsel. Electronic notifications should be sent to the Executive Secretary at mpscedockets@michigan.gov and to the Michigan Department of the Attorney General – Public Service Division at pungp1@michigan.gov. In lieu of electronic submissions, paper copies of such notifications may be sent to the Executive Secretary and the Attorney General – Public Service Division at 7109 W. Saginaw Hwy., Lansing, MI 48917.

MICHIGAN PUBLIC SERVICE COMMISSION



Daniel C. Scripps, Chair



Tremaine L. Phillips, Commissioner

By its action of June 23, 2022.



Lisa Felice, Executive Secretary

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of an Integrated Resource Plan	)	Case No. U-21090
under MCL 460.6t, certain accounting	)	
approvals, and for other relief.	)	
_____	)	

SETTLEMENT AGREEMENT

Pursuant to MCL 24.278 and Rule 431 of the Michigan Administrative Hearing System’s Rules of Practice and Procedure before the Michigan Public Service Commission (“MPSC” or the “Commission”), the undersigned parties agree as follows:

WHEREAS, on June 30, 2021 Consumers Energy Company (“Consumers Energy” or the “Company”) filed an Application requesting approval of the Company’s Integrated Resource Plan (“IRP”) pursuant to Section 6t of 2016 PA 341, MCL 460.6t, the Commission’s June 7, 2019 Order Approving Settlement Agreement in Case No. U-20165, and all other orders and applicable law. The Company filed testimony and exhibits in support of its positions concurrently with its Application.

WHEREAS, the initial prehearing conference was held on July 22, 2021 before Administrative Law Judge (“ALJ”) Sally L. Wallace. Beyond the Company, the parties to the IRP are: the MPSC Staff (“Staff”); the Attorney General; Hemlock Semiconductor Operations, LLC (“HSC”); the Biomass Merchant Plants (“BMPs”)¹; Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club (“MNS”); Great Lakes Renewable Energy

¹ The BMPs consist of: Cadillac Renewable Energy, LLC, Genesee Power Partners Limited Partnership, Decker Energy-Grayling, LLC, Hillman Power Company, LLC, Tondur Corporation, National Energy of Lincoln, LLC, f/k/a Viking Energy of Lincoln, LP and National Energy of McBain, f/k/a Viking Energy of McBain, LLC.

Association (“GLREA”), Environmental Law and Policy Center, the Ecology Center, Vote Solar, and the Union of Concerned Scientists (collectively, the Clean Energy Organizations (“CEO”)); Residential Customer Group (“RCG”); Association of Businesses Advocating Tariff Equity (“ABATE”); Michigan Energy Innovation Business Council, Institute for Energy Innovation, and the Clean Grid Alliance (collectively, “Michigan EIBC/IEI/CGA”); Energy Michigan, Inc. (“Energy Michigan”); Midland Cogeneration Venture Limited Partnership (“MCV”); Michigan Electric Transmission Company, LLC (“METC”); Michigan Public Power Agency (“MPPA”); Wolverine Power Supply Cooperative (“Wolverine”); the Citizens Utility Board (“CUB”); the Mackinac Center for Public Policy (“Mackinac”); and the Urban Core Collective (“UCC”). 1 TR 11-12, 22.

WHEREAS, Consumers Energy filed testimony and exhibits requesting approval of the Company’s IRP Proposed Course of Action (“PCA”) in its entirety, as the most reasonable and prudent means of meeting the Company’s energy and capacity needs through 2040. The Company specifically requested the Commission to make the following determinations:

- (i.) Approve Consumers Energy’s PCA, which is inclusive of all proposals presented by the Company in this case, including the battery deployment program, as the most reasonable and prudent means of meeting the energy and capacity needs of the Company and its customers;
- (ii.) Approve the Company’s acquisition and proposed purchase costs for the New Covert Generating Facility (“Covert Plant”) and Dearborn Industrial Generation (“DIG Plant”), the Livingston Generating Station (“Livingston Plant”), and the Kalamazoo River Generating Station (“Kalamazoo Plant”), in the manner proposed by the Company, and proposed Energy Waste Reduction (“EWR”), Demand Response (“DR”), and Conservation Voltage Reduction (“CVR”) costs which will be commenced by the Company within three years following the Commission’s expected approval of the Company’s IRP;
- (iii.) Approval of the selection and proposed purchase of the DIG, Kalamazoo, and Livingston plants, by the Company from its affiliate, CMS Enterprises. The transaction was a result of a competitive solicitation and is compliant with the Commission’s Code of Conduct requirements. In the alternative, while complying with all other provisions of the Code of Conduct, the Company

requests a waiver of the asset transfer provision of the Code of Conduct, Mich Admin Code R 460.10108(4), for the acquisition of the DIG, Livingston, and Kalamazoo plants, from CMS Enterprises;

- (iv.) Approve the Company's proposal to recover the unrecovered book balances of D.E. Karn ("Karn") Units 3 and 4 and J.H. Campbell ("Campbell") Units 1, 2, and 3, including decommissioning costs, through regulatory asset treatment, with full return, over the design lives of those units;
- (v.) Approve the Company's proposals to: (i) defer employee retention costs related to the proposed accelerated retirements of Karn Units 3 and 4 and Campbell Units 1, 2, and 3, and (ii) defer retirement transition costs for future recovery;
- (vi.) Approve the Company's proposed modifications to its Public Utility Regulatory Policies Act of 1978 ("PURPA") construct and the Company's proposed competitive procurement process and the use of that competitive procurement process for: (i) determining PURPA avoided costs rates, and (ii) determining and addressing the Company's capacity position under PURPA;
- (vii.) Determine that the Company has no PURPA capacity need so long as the Company is implementing the PCA, with the competitive procurement process proposed by the Company; and
- (viii.) Approve the Company's proposed Financial Compensation Mechanism ("FCM") for any new, or newly amended, Power Purchase Agreements ("PPAs") entered into by the Company.

Staff and other intervening parties filed testimony and exhibits addressing various issues.

NOW THEREFORE, for purposes of settlement of Case No. U-21090, the undersigned parties agree as follows:

1. The parties agree that the Company's PCA, as modified in this Settlement Agreement, should be approved as the most reasonable and prudent means of meeting the Company's energy and capacity needs over the 5-year, 10-year, and 15-year time horizons. The parties agree that the Company will file its next IRP consistent with the requirements of MCL 460.6t.

2. The parties agree that the PCA shall include the Company's proposed purchase of the Covert Plant in 2023 but shall not include the ownership of the DIG, Kalamazoo, and

Livingston plants. The parties agree that the identified capital costs that the Company will incur for DR (\$23,751,000), CVR (\$9,736,315), and the purchase of the Covert Plant (\$815 million) in the next three years (June 2022 – June 2025) are reasonable and prudent and approved for cost recovery purposes and will be included in rates in a future Company rate case consistent with MCL 460.6t(11) and (17). The parties further agree to the approval of the projected capacity value provided by the Covert Plant and the DR (projected to achieve a total of 641 MW (657 Zonal Resource Credits (“ZRCs”)) by 2025), CVR (projected to achieve 136,351 MWh savings by 2025, 56.81 MW savings by 2025), and EWR (projected to achieve 545,305 MWh savings in 2025, 879 MW savings by 2025) resources included in the PCA during the next three years. The parties further agree that the Company shall continue to file an annual reporting template with the Commission addressing the implementation of the approved DR and CVR resources above.

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

4. The parties agree that (i) Karn Units 3 and 4 will be retired on or before May 31, 2031, absent extraordinary circumstances that require prolonged operation, such as a System Support Resource designation by Midcontinent Independent System Operator, Inc. (“MISO”) or other emergent issues within the Company’s generation portfolio which require continued

operation of Karn Units 3 and 4 to maintain sufficient supply; and (ii) Campbell Units 1, 2, and 3 will be retired on or before May 31, 2025.

5. The parties agree that the Company will not file an application for a financing order for the unrecovered book balance and decommissioning costs of Campbell Units 1, 2, and 3. The parties agree that the Commission will permit Consumers Energy to recover the unrecovered book balance of Campbell Units 1, 2, and 3 through the Company's proposed regulatory asset treatment, with a return equal to the Company's weighted average cost of capital ("WACC") premised on the return on equity approved by the Commission in rate cases prior to the retirement date of those units and a 9.0% return on equity after the retirement date of those units, as part of the Company's electric rates over the current design lives of those units. The 9.0% return on equity will be used to modify the capital structure filed with each rate case and the return on equity will be the only modification to the capital structure used to calculate the return on the regulatory asset after the retirement date of the units. The parties further agree that the Company will be permitted to record a regulatory asset for actual decommissioning spending for Campbell Units 1, 2, and 3, with a return on the regulatory asset, with subsequent rate recovery in a rate case after a review of the reasonableness and prudence of the expenses. Recovery of the associated decommissioning and ash disposal costs will be treated as follows:

- a. The decommissioning costs, less salvage value, related to Campbell Units 1, 2, and 3 and the ash disposal costs related to Campbell Units 1, 2, and 3 will be recorded, as spent, to a regulatory asset; and
- b. The Company may request recovery in future base rate proceedings, and upon Commission determination that the Company has incurred those costs as the result of reasonable and prudent actions, they shall be included in rates. The Company will ensure that the amounts recovered through a regulatory asset account are net of any accumulated depreciation amounts.

6. The parties agree that subsequent to the Commission's order approving this Settlement Agreement, the Company shall issue a competitive solicitation ("the One-Time Solicitation") which will include the following parameters:

- a. The One-Time Solicitation will seek projects which will provide the Company with capacity credit in the MISO Zone 7 starting in the 2025 Planning Year;
- b. The One-Time Solicitation will include two all source tranches:
 - i. The first tranche will seek up to 500 ZRCs of capacity and associated energy and renewable energy credits ("RECs"), if applicable, from PPAs with terms up to 10 years. This tranche will seek dispatchable, non-intermittent generation capable of dispatching up or down in every hour of the year in response to wholesale energy market signals, providing capacity which meets the Local Clearing Requirement of MISO Zone 7; and
 - ii. The second tranche will seek up to 200 ZRCs of capacity and associated energy and RECs, if applicable, secured from unaffiliated third parties via PPAs or other third-party agreements that do not result in Company ownership with terms up to 25 years, at the discretion of the bidder. This tranche will seek intermittent resources and dispatchable, non-intermittent clean capacity resources (including battery storage resources), providing capacity which meets the Local Clearing Requirement of MISO Zone 7. This tranche will furthermore take into consideration the ability of the offered capacity to meet the Local Clearing Requirement of MISO Zone 7 for the duration of the contract length. Prior to the issuance of the second tranche portion of the One-Time Solicitation, the Company shall hold a stakeholder meeting including parties to this case and energy storage developers to discuss methods to improve RFPs and response to solicitations with respect to stand-alone storage projects and hybrid-storage projects.
- c. The Company's acquisition of the 700 ZRCs and associated energy and RECs, if applicable, sought in the One-Time Solicitation shall be considered incorporated into the PCA approved in Paragraph 1 of this Settlement Agreement. However, the actual selected bid(s) will be submitted in Case No. U-21090 for Commission approval subsequent to the completion of the One-Time Solicitation;
 - i. In that approval proceeding, the Commission shall: (i) confirm whether the solicitation process followed by the Company is consistent with the requirements of the Settlement Agreement; (ii) grant approval of the recovery of the costs associated with the selected project(s) pursuant to applicable law or make a preliminary finding that the costs associated

with the project(s) that prevail in the solicitation are reasonable and prudent; and (iii) grant any other approvals or findings necessary as required or provided by applicable law.

- d. The One-Time Solicitation will not be used to set the Company's avoided costs rates or capacity needs under PURPA.

7. The parties agree to the approval of the Company's proposed accounting request to defer expense related to the Campbell site severance and retention agreement, utilizing a regulatory asset to record the deferred amounts. The deferred amounts for 2022 will be capped at \$26 million. All amounts deferred for 2022 and beyond will be reviewed in future rate cases. This Settlement Agreement does not permit the Company to defer amounts related to the Campbell site severance and retention agreement outside of 2022.

- a. Consumers Energy will publicly file in Case No. U-21090 its community transition plan for Karn Units 1 through 4 within 150 days of all four Karn Units ceasing operation; and
- b. Consumers Energy will develop a draft community transition plan for the Campbell site. During the development of this draft community transition plan for the Campbell site, Consumers Energy will consult with community-based organizations and community members living in the area surrounding the retired assets on the community transition plan before finalizing and filing it for informational purposes in Case No. U-21090.

8. The parties agree to the extension of the annual competitive bidding process used to acquire the supply-side resource technologies specified in the PCA, as approved in Case No. U-20165 (collectively the "Annual Solicitations" and individually an "Annual Solicitation"), with certain modifications included below:

- a. Qualifying Facilities ("QFs") that the Company has a legal obligation to purchase from under PURPA (such facilities are referred to as "QFs" in this Settlement Agreement), may bid any technology into the Annual Solicitation but will be required to submit an offer consistent with the PPA terms sought in the Annual Solicitation;
- b. The competitive bid process shall be administered by an independent third party. The evaluation criteria and process is to be made available to all bidders submitting responses for the specific technology requested by the

Company, as part of the RFP, to ensure transparency. QFs may bid any technology that meets the requirements of PURPA. A ranking of proposals is to be used by the independent third party and provided to the Company for selection;

- c. In its September 9, 2021 Order in Case No. U-20852 the Commission adopted competitive bidding guidelines titled “Competitive Procurement Guidelines for Rate-Regulated Electric Utilities (Not for PUPRA Compliance) and “Competitive Procurement Guidelines For Rate-Regulated Electric Utilities for PURPA Avoided Cost and Capacity Determination.” The “Objective” of the adopted guidelines provides that when the guidelines are utilized by utilities, it is presumed that resulting projects and contracts are reasonable and prudent and in the event utilities diverge from the guidance provided in the guidelines, it is expected that the utility will provide sufficient justification in order to receive Commission approval and recovery. In the Annual Solicitation process, the Company will follow the Commission’s adopted guidelines, including the ability to diverge from the guidance as provided in the guidelines;
- d. The first competitive solicitation for the Company pursuant to this Settlement Agreement will be conducted no later than December 31, 2022. New full avoided cost rates stemming from each competitive solicitation will be filed with the Commission for review and approval within 30 days of the conclusion of each competitive solicitation;
- e. The Company will seek term lengths for competitively bid projects up to 25 years, at the discretion of the bidder;
- f. The Company will seek to acquire the target amount of capacity identified in the PCA for each Annual Solicitation period and may exceed that target amount depending on the amount of bids, the size of projects bid, cost and value, and variations in project commercial operation dates. Total newly acquired capacity will be reconciled against the amount of capacity projected in the PCA in the Company’s next IRP. (For example, if the Company acquired more capacity than planned, the proposed resource plan in the next IRP would incorporate that additional capacity with a potential reduction in the capacity needed going forward.);
- g. If the Company is unable to meet the target capacity amount identified in the PCA in any given Annual Solicitation, the remaining "open" capacity will not be offered to QFs. The remaining capacity would instead be addressed through the process described in Paragraph 8.f.;
- h. The parties agree and acknowledge that there are supply chain, energy security, labor, and environmental benefits associated with robust, local clean energy manufacturing capabilities. As part of the Company’s competitive bidding process, the parties agree that the Company will, to the extent

reasonably possible, incorporate clear, fair, and transparent criteria in the bid evaluation process to recognize value associated with clean energy supply chain diversification and sustainability, including intended use of Michigan manufactured components and low-carbon manufacturing as verifiable by life cycle assessment and/or disclosure using public, third-party verified environmental product declarations. The Company agrees to consult with parties to the settlement on the details of such bid evaluation criteria. Nothing in this settlement alters the opportunity for stakeholders and potential bidders to review and comment on any new proposed bidding criteria through the process as set forth in the MPSC's competitive bidding guidelines approved in MPSC Case No. U-20852 on September 9, 2021;

- i. The parties agree that the Annual Solicitation process does not restrict the Company's ability to make short-term capacity additions to address capacity shortfalls which cannot reasonably be addressed through the Annual Solicitation process; and
- j. The Company may pursue supply-side resource pilots for new and emerging technologies outside of an Annual Solicitation subject to cost and project approval in its future rate cases.

9. The parties agree that the new capacity that the Company intends to procure through the PCA, in each Annual Solicitation, shall be: (i) acquired through a competitive bidding process; and (ii) approximately 50% will be from PPAs and other third-party agreements that do not result in Company ownership and approximately 50% will be owned by the Company, as acquired through a competitive bidding process. The new capacity acquired from PPAs or other third-party agreements that do not result in Company ownership will not compete against the new capacity which will be owned by the Company. The Company will use commercially reasonable efforts to maintain the 50%/50% proportion for new IRP resources from 2022 through the Company's next IRP proceeding, and in no event shall any given annual solicitation result in the Company owning more than 60% of the new capacity acquired in such solicitation. The Company, in its sole discretion, may also choose to acquire more than 50% of its new capacity from third parties. The parties further agree that the Company's affiliates will

be prohibited from bidding on the portion of the Company's new capacity acquired from third parties.

10. The parties agree to the approval of the extension of the Company's FCM approved in Case No. U-20165 equal to the product of: (i) the annual PPA payment, and (ii) the Company's after-tax WACC based on its total capital structure, which is currently 5.62%, as updated from time to time by the MPSC in electric rate case final orders. The FCM will be applicable to all new PPAs, but will not apply to PPA amendments, PURPA PPAs, and Voluntary Green Pricing PPAs. The Company shall also not receive an FCM on any PPAs executed under the Company's Renewable Energy Plan. The FCM will be subject to the cap, as provided in Attachment A of the Settlement Agreement. The parties agree that nothing in this Settlement Agreement is intended to waive the requirements of MCL 460.6t(15).

11. The parties agree to the extension of the Company's PURPA avoided cost construct, as approved in Case No. U-20165 (based on the Company's Annual Solicitations), with certain modifications included below:

- a. The Company's PURPA avoided cost construct will be subject to review in the Company's future IRP filings, as opposed to separate biennial filings;
- b. QFs 150 kWac and below are eligible to receive full avoided cost rates regardless of the Company's capacity needs;
- c. Within 180 days subsequent to the Commission's approval of this Settlement Agreement, the Company shall initiate stakeholder outreach to develop a simplified agreement, tariff-based program, or other mechanism which will allow QFs 150 kWac and below to receive full avoided cost rates. Subsequent to the completion of the stakeholder outreach, at the earliest practicable date, the Company will file a proposal with the Commission for approval;
- d. When the Company does not have a PURPA capacity need, QFs above 150 kWac, that the Company has a legal obligation to purchase from under PURPA, are eligible to receive the Company's energy-only avoided cost rates. The Company's energy-only avoided cost rates shall be based on a forecast of LMPs for the first 5 years and actual LMPs for years 6 through 10. The

Company's energy-only avoided cost rates shall not include a payment for capacity;

- e. Current existing QFs, at or below the Company's PURPA must-purchase obligation MW threshold, with a PURPA-based PPA with the Company as of January 1, 2019 shall receive new PPAs, regardless of the Company's capacity need, upon the expiration of their current PPAs based on the Company's full avoided cost rates at the time of PPA expiration. QFs that entered a PPA with the Company prior to January 1, 2019 at an amount less than full avoided cost rates, such as reduced avoided cost rates based on the Planning Resource Auction ("PRA") rate and forecasted or actual LMPs and energy-only rates which only include an energy rate and do not provide a payment for capacity, shall not automatically receive a new PPA at the full avoided cost rate when their current PPA expires. QFs that have entered a PPA with the Company after January 1, 2019 are not eligible to receive a new full avoided cost rate PPA with the Company regardless of the Company's capacity need;
- f. QFs that the Company has a legal obligation to purchase from under PURPA, and which are eligible for full avoided cost rates, may select PPA terms up to 20 years; and
- g. QFs up to 5 MWac, that the Company has a legal obligation to purchase from under PURPA, are eligible for the Company's PURPA Standard Offer Tariff and Standard Offer Contract. The terms of the Standard Offer Contract will also be updated from using the MISO methodology for capacity accreditation at the time of PPA execution, to the average of the MISO methodologies at the time of PPA execution and delivery under the PPA. Within 30 days following the Commission's approval of this Settlement Agreement, the Company shall file revised Standard Offer tariff sheets and a revised Standard Offer contract, to reflect the Standard Offer construct and rates approved as part of this Settlement Agreement. Parties shall be given 14 calendar days subsequent to the Company's filing to provide comments to the Commission.

12. The Company has no PURPA capacity need so long as the Company is implementing the Commission-approved PCA, as provided in Paragraph 1, including the competitive Annual Solicitation process for future capacity needs.

13. The parties agree that the Company will donate \$5 million in 2022 to a low-income fund that provides bill assistance to Consumers Energy's electric customers. The Company will also donate \$2 million annually to the same low-income fund each year during the amortization period for the regulatory asset, provided in Paragraph 5 of this Settlement

Agreement, with each annual donation contingent on the Company filing and the Commission approving a Voluntary Revenue Refund (“VRR”). The donations described in this paragraph will not be recovered in rates and Consumers Energy will consult with the Attorney General and Staff on the low-income fund receiving the donations. The Company will provide an annual report to the Commission each year a donation is made. If known, the report will include the number of households served, the number of households over 150% of the federal poverty level (“FPL”), and number under 150% of the FPL. For those households 150% of FPL and under, the report will explain, if known, whether they are receiving the funds because they exhausted other benefits such as the Michigan Energy Assistance Program or State Emergency Relief.

14. In future IRPs, beginning with its next IRP, the Company will (i) collect the necessary data to compute marginal line losses and report these with average line losses and (ii) include marginal line losses and avoided transmission and distribution costs in its evaluation of all distributed resources, including residential DR potential.

15. Consumers Energy agrees to develop a distributed generation as a resource model approach that considers economic distribution connected solar to be modeled by bundling resources installed at the customer level to compare the total economic costs to the utility of distributed generation as a resource to other selectable supply-side resources, consistent with the methodology used for EWR. The Company will develop a model that accounts for all utility costs and/or incentives associated with participating and non-participating distributed generation customers. The Company agrees to present the model approach for stakeholder review and feedback prior to the next IRP. The model approach, including any incorporated stakeholder feedback, will be included into the Company’s next IRP.

16. The parties agree that Consumers Energy's IRP set forth a proposal to be Carbon Neutral by 2040 and retire all coal generation by 2025, 14 years ahead of the original timeline. These retirements include two substantial coal and gas units totaling approximately 2,000 MW. To replace the capacity, Consumers Energy has proposed adding existing natural gas-fired generation and plans to add about 8,000 MW of solar generation by 2040, to dramatically reduce the use of fossil fuel resources. The next IRP should consider transmission and how it can facilitate the mitigation of reliability and economic impacts to the electric system. The parties also agree that strategic investment in electric transmission needs continual assessment to understand the role of transmission in allowing for the most economic path to meeting the state's energy goals while complementing Michigan's Load Serving Entities' ("LSE") objectives. Michigan is transitioning its generation portfolio and must take the appropriate steps to increase system reliability, resiliency, flexibility, and affordability. Michigan will be better positioned by taking a forward-looking approach regarding resource adequacy. The state should continue to recognize and support the value of a multitude of resources such as Solar, Wind, DR, and Distributed Energy Resources which assist in an "all of the above" approach. Transmission is essential in delivering the reliability of these resources. The value of transmission can be even further realized by leveraging those transmission resources to better assist the Consumers Energy IRP. This will allow MISO LRZ 7 to access broader pools of generation resources, be better situated for future demands placed on the system, mitigate unnecessary risks, and increase performance of those "all of the above" resources to serve the demands of Michigan's customers reliably and economically.

17. The parties agree that the Company will include the following analysis in its next IRP:

- a. The Company will provide total emissions, in lbs or tons, and rate of emissions, in lbs or tons per MWh and per MMBtu, for each owned power plant unit, or units that the Company has a power purchase agreement with, for the last 5 years of operation (for existing units) and projected for the next 5 years (for all units) for the following pollutants: carbon dioxide, nitrogen oxides, sulfur dioxide, volatile organic compounds (“VOCs”), and primary particulate matter (“PM2.5”);
- b. The Company will calculate the annual PM2.5-related health impacts associated with each power plant’s emissions. The modeling will include the impacts from primary PM2.5 emissions and PM2.5 precursors emissions (nitrogen oxides, sulfur dioxide, VOCs). The Company will use one model to evaluate the number and economic value of PM2.5-related health impacts of these emissions. The Company may use COBRA or BenMAP (which will require pollutant change inputs from another model such as InMAP) for these calculations, or models that are of equal or greater complexity and accuracy. The Company will report the total number and economic value of PM2.5-related health impacts across the US for the chosen model and spatially by Michigan county or at a higher resolution;
- c. The Company will use the MiEJScreen mapping and screening tool, or, if the MiEJScreen tool is not yet finalized, the EPA Environmental Justice Screening and Mapping Tool (“EJSCREEN”), to assess populations in a 1-mile and 3-mile buffer around each power plant location, including reporting total populations and any indicators and total index results above the 75th percentile;
- d. The Company will report projected low-income energy efficiency participation levels, low-income load-reduction data, and publicly available rooftop solar adoption rates. If available, information on rooftop solar adoption by low-income customers will be provided;
- e. The Company will include a narrative discussion of how the data obtained in a-d were considered by the utility; and
- f. To the extent that the Commission formally adopts revised Integrated Resource Plan Filing Requirements and/or revised Michigan Integrated Resource Planning Parameters that address environmental emissions, health impacts from emissions, or environmental justice, such filing requirements will supersede the terms of this Paragraph 17.

18. The parties agree that the Company will take the following steps to engage and gather input from the public prior to the filing of its next IRP with the Commission:

- a. Host meetings about the topic of the filing at a variety of times, during the daytime and the evening, with the Company providing equivalent content and equivalent and sufficient time for robust public response at each session;
- b. Host meetings about the topics in the filing with a roughly equal mix between (i) in-person meetings and (ii) virtual or hybrid meetings;
- c. For the duration of the proceedings before the MPSC, make available on its website recordings of (i) all virtual or hybrid meetings and (ii) to the extent feasible, any portion of an in-person meeting in which the Company is (a) addressing all participants in the meeting and/or (b) receiving public feedback and/or questions in a format intended to be heard by all participants in the meeting at the same time;
- d. When requested 10 business days prior to a meeting, provide translations of materials for the benefit of those communities whose first language is not English, based on the demographics of the community;
- e. When requested within 30 days subsequent to a meeting, the Company will use best efforts to provide a translation of recordings of the community meeting in a language specified by the person requesting the translation. Such translation recordings will be provided within 15 business days, subject to the Company's best efforts, after the request is received. If the Company is unable, after a good faith effort, to find or reasonably engage the services of a translator capable of translating the recording into the language requested, the Company will not be obligated to provide the translation;
- f. When requested at least 10 business days prior to an in-person meeting, the Company will use best efforts to include at least one live interpreter who can translate in the requested language. If the Company is unable, after a good faith effort, to find or reasonably engage the services of a translator capable of translating the meeting into the language requested, the Company will not be obligated to provide the translation;
- g. Coordinate with community-based organizations when organizing and promoting meetings about the filing. The Company will solicit input regarding the time, place, and manner of the meetings from the community organizations, in addition to any other meetings the Company wishes to hold of its own accord;
- h. Use best efforts to present the details of the integrated resource planning process in accessible, non-technical language that includes, but is not limited to, descriptions of the impacts of the Company's plans on communities, the environment, and public health;
- i. Include in its filings a concise general statement of the basis and purpose of the comments received by the Company and how the Company considered,

addressed, or rejected the issues raised in those comments in the IRP (as practicable); and

- j. Subsequent to the issuance of the Commission's order approving this Settlement Agreement, the Company agrees to meet with UCC to discuss potential stakeholder outreach prior to or subsequent to future electric rate case filings.

19. The parties agree that the Company will do the following with respect to combined heat and power ("CHP") resources:

- a. Within 180 days of the effective date of the Commission's order approving the settlement, the Company will initiate a voluntary survey among its commercial and industrial customers to gauge interest in CHP (the "CHP survey"), with survey responses intended to be used by the Company to support the evaluation of: (1) the types of CHP that customers prefer, with regard to size, technology and overall configuration, on both the demand side and supply side, including co-ownership arrangements and other potential partnerships with the Company, and: (2) non-confidential information regarding locations within the Consumers Energy territory that may be most appropriate for deployment of CHP. The CHP survey will be conditioned on respondent approval of the public release of all information provided by the respondent in response to the survey. Nothing in this section is intended to require the public release of any confidential and/or commercially sensitive customer or Company information;
- b. Within 360 days of the effective date of the Commission's order approving the settlement, the Company will share the results of the CHP survey in the Case No. U-21090 e-docket, including a summary of the types of CHP that customers prefer, with regard to size, technology, and overall configuration, on both the demand side and supply side, including co-ownership arrangements and other potential partnerships with the Company; and a summary of non-confidential information regarding locations within the Company's territory that may be most appropriate for deployment of CHP, according to the CHP survey results;
- c. In its next IRP proceeding, the Company will model behind-the-meter CHP representative of a demand-side resource based upon the results from the CHP survey as appropriate; and
- d. In its next IRP proceeding, the Company will model front-of-the-meter CHP configurations based upon the results from the CHP survey as appropriate.

20. This settlement is entered into for the sole and express purpose of reaching a compromise among the parties. All offers of settlement and discussions relating to this settlement are, and shall be considered, privileged under MRE 408. If the Commission approves this Settlement Agreement without modification, neither the parties to this Settlement Agreement nor the Commission shall make any reference to, or use, this Settlement Agreement or the order approving it, as a reason, authority, rationale, or example for taking any action or position or making any subsequent decision in any other case or proceeding; provided, however, such references may be made to enforce or implement the provisions of this Settlement Agreement and the order approving it.

21. This Settlement Agreement is based on the facts and circumstances of this case and is intended for the final disposition of Case No. U-21090. So long as the Commission approves this Settlement Agreement without any modification, the parties agree not to appeal, challenge, or otherwise contest the Commission order approving this Settlement Agreement. Except as otherwise set forth herein, the parties agree and understand that this Settlement Agreement does not limit any party's right to take new and/or different positions on similar issues in other administrative proceedings, or appeals related thereto.

22. This Settlement Agreement is not severable. Each provision of the Settlement Agreement is dependent upon all other provisions of this Settlement Agreement. Failure to comply with any provision of this Settlement Agreement constitutes failure to comply with the entire Settlement Agreement. If the Commission rejects or modifies this Settlement Agreement or any provision of the Settlement Agreement, this Settlement Agreement shall be deemed to be withdrawn, shall not constitute any part of the record in this proceeding or be used for any other purpose, and shall be without prejudice to the pre-negotiation positions of the parties.

23. The parties agree that approval of this Settlement Agreement by the Commission would be reasonable and in the public interest.

24. The parties agree to waive Section 81 of the Administrative Procedures Act of 1969 (MCL 24.281), as it applies to the issues resolved in this Settlement Agreement, if the Commission approves this Settlement Agreement without modification.

WHEREFORE, the undersigned parties respectfully request the Commission to approve this Settlement Agreement on an expeditious basis and to make it effective in accordance with its terms by final order.

MICHIGAN PUBLIC SERVICE COMMISSION STAFF

By: **Spencer Sattler**
Digitally signed by Spencer Sattler
Date: 2022.04.19 14:00:30 -04'00'

Date: April 19, 2022

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Amit T. Singh, Esq.
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CONSUMERS ENERGY COMPANY



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Date: April 19, 2022

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ATTORNEY GENERAL, DANA NESSEL

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Date: _____

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GREAT LAKES RENEWABLE ENERGY ASSOCIATION

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Public Law Resource Center PLLC
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Date: April 19, 2022

MICHIGAN ENVIRONMENTAL COUNCIL



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Date: April 19, 2022

NATURAL RESOURCES DEFENSE COUNCIL



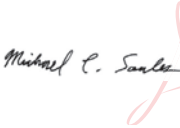
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SIERRA CLUB

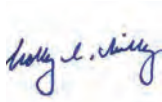
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CITIZENS UTILITY BOARD OF MICHIGAN



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by Holly L. Hillyer
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MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL, INSTITUTE FOR ENERGY
INNOVATION, AND CLEAN GRID ALLIANCE

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MICHIGAN ELECTRIC TRANSMISSION COMPANY, LLC

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ENVIRONMENTAL LAW & POLICY CENTER, VOTE SOLAR, ECOLOGY CENTER, AND
UNION OF CONCERNED SCIENTISTS

By: 
Margrethe Kearney, Esq.
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Date: April 19, 2022

HEMLOCK SEMICONDUCTOR OPERATIONS LLC

By: **Jennifer
Utter
Heston**  Digitally signed by
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Date: April 19, 2022

URBAN CORE COLLECTIVE



By:

Nicholas Leonard, Esq.
Andrew Bashi, Esq.
Great Lakes Environmental Law Center
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19-April-2022

Date:

Mark N. Templeton, Esq.
Robert A. Weinstock, Esq.
University of Chicago Law School –
Abrams Environmental Law Clinic
6020 South University Avenue
Chicago, IL 60637

The following parties do not wish to be signatories to this Settlement Agreement; however they have agreed to sign below to indicate non-objection to the Settlement Agreement.

MICHIGAN PUBLIC POWER AGENCY

By: Nolan J. Moody Digitally signed by Nolan J. Moody
Date: 2022.04.19 12:19:10 -04'00'

Date: April 19, 2022

Nolan J. Moody, Esq.
Peter H. Ellsworth, Esq.
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MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP

By: **John**
Janiszewski
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= jjaniszewski@dykema.com C =
US O = Dykema Gossett, PLLC
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John A. Janiszewski, Esq.
Dykema Gossett PLLC
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Lansing, MI 48933

Date: April 20, 2022

ATTACHMENT A

ATTACHMENT A

Contract Year	Total Rate (\$/MWh)
2019	\$ 55.54
2020	\$ 57.49
2021	\$ 59.38
2022	\$ 61.28
2023	\$ 63.25
2024	\$ 65.24
2025	\$ 67.24
2026	\$ 69.24
2027	\$ 71.23
2028	\$ 73.18
2029	\$ 75.08
2030	\$ 76.95

PROOF OF SERVICE

STATE OF MICHIGAN)

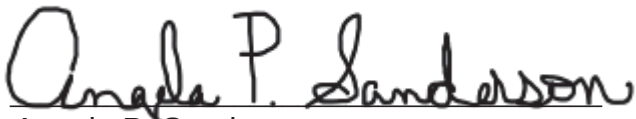
Case No. U-21090

County of Ingham)

Brianna Brown being duly sworn, deposes and says that on June 23, 2022 A.D. she electronically notified the attached list of this **Commission Order via e-mail transmission**, to the persons as shown on the attached service list (Listserv Distribution List).


Brianna Brown

Subscribed and sworn to before me
this 23rd day of June 2022.



Angela P. Sanderson
Notary Public, Shiawassee County, Michigan
As acting in Eaton County
My Commission Expires: May 21, 2024

Service List for Case: U-21090

Name	Email Address
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Christopher M. Bzdok	chris@envlaw.com
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Tracy Jane Andrews	tjandrews@envlaw.com

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Midcontinent)
Independent System Operator)
(MISO))

Order No. 202-26-16

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 10

Blumenstock 2023 Direct
Testimony

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21389

Volume 4

_____/

CROSS-EXAMINATION

Proceedings held via Microsoft Teams in the
above-entitled matter before Sally Wallace,
Administrative Law Judge with MOAHR, for the Michigan
Public Service Commission, Lansing, Michigan, on
Wednesday, October 11, 2023 at 10:04 a.m.

APPEARANCES:

GARY A. GENSCH, JR., ESQ.
MICHAEL C. RAMPE, ESQ.
One Energy Plaza Drive
Jackson, Michigan 49201

On behalf of Consumers Energy Company

NICHOLAS TAYLOR, ESQ.
ANNA STIRLING, ESQ.
AMIT SINGH, ESQ.
MONICA STEPHENS, ESQ.
ALENA CLARK, ESQ.
Assistant Attorneys General
7109 West Saginaw Highway, Floor 3
Lansing, Michigan 48909

On behalf of Michigan Public Service
Commission Staff

(Continued)

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-21389
the generation and distribution of	)	
electricity and for other relief.	)	
_____	)	

DIRECT TESTIMONY

OF

RICHARD T. BLUMENSTOCK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

RICHARD T. BLUMENSTOCK
DIRECT TESTIMONY

1 **Q. Please state your name and business address.**

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

4 **Q. By whom are you employed?**

5 A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”).

6 **Q. What is your position with Consumers Energy?**

7 A. I am currently the Executive Director of Electric Supply Engineering. I began employment
8 at the Company in May 1994 in the electric transmission planning area where I performed
9 planning studies on the Company’s distribution and transmission systems. In April 2002,
10 I was assigned to the electric operations area where I oversaw engineering operations for
11 the distribution and transmission systems. In August 2009, I was assigned to the fuel
12 supply area where I oversaw the Company’s purchasing and transport functions for fuel
13 for electric generation. In June 2011, I assumed additional responsibilities including
14 oversight of the Company’s interaction in the Midcontinent Independent System Operator,
15 Inc. (“MISO”) markets; wholesale settlements and transactions functions; Power Supply
16 Cost Recovery (“PSCR”) activities; and planning for electric supply necessary to satisfy
17 customers’ energy and capacity needs. In September 2019, I assumed the role of Executive
18 Director of Electric Planning, overseeing the company-wide efforts for all electric
19 planning. In September 2022, I assumed my current position as Executive Director of
20 Electric Supply Engineering.

RICHARD T. BLUMENSTOCK
DIRECT TESTIMONY

1 **Q. What are your responsibilities as Executive Director of Electric Supply Engineering?**

2 A. My responsibilities as Executive Director of Electric Supply Engineering include oversight
3 of all activities associated with planning and design for the Company's electric generation
4 portfolio.

5 **Q. What is your formal educational experience?**

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

8 **Q. Have you previously provided testimony before the Michigan Public Service
9 Commission ("MPSC" or the "Commission")?**

10 A. Yes, I provided testimony in the following MPSC cases:

- 11 • Case No. U-16045-R: Reconciliation of PSCR Costs and Revenues for the
12 Calendar Year 2010;
- 13 • Case No. U-16432-R: Reconciliation of PSCR Costs and Revenues for the
14 Calendar Year 2011;
- 15 • Case No. U-16890: Approval of a PSCR Plan and for Authorization of Monthly
16 PSCR Factors for the Year 2012;
- 17 • Case No. U-16890-R: Reconciliation of PSCR Costs and Revenues for the
18 Calendar Year 2012;
- 19 • Case No. U-17429: Approval of a Certificate of Necessity for the Thetford
20 Generating Plant pursuant to MCL 460.6s and for related accounting and
21 ratemaking authorizations;
- 22 • Case No. U-17317: Approval of a PSCR Plan and for Authorization of Monthly
23 PSCR Factors for the Year 2014;
- 24 • Case No. U-17317-R: Reconciliation of PSCR Costs and Revenues for the
25 Calendar Year 2014;
- 26 • Case No. U-17752: Authority to amend its renewable energy plan approved in
27 Case Nos. U-15805, U-16543, U-16581, and U-17301;
- 28 • Case No. U-17678: Approval of a PSCR Plan and for Authorization of Monthly
29 PSCR Factors for the Year 2015;

RICHARD T. BLUMENSTOCK
DIRECT TESTIMONY

- Case No. U-17678-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2015;
- Case No. U-18250: Application of Consumers Energy for a financing order approving the securitization of qualified costs and related approvals associated with the early termination of the Palisades Nuclear Energy Plant Power Purchase Agreement;
- Case No. U-20134: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief;
- Case No. U-20165: Application of Consumers Energy for approval of its Integrated Resource Plan (“IRP”) pursuant to MCL 460.6t and for other relief;
- Case No. U-20697: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief;
- Case No. U-20963: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief;
- Case No. U-21090: Application of Consumers Energy for Approval of an IRP under MCL 460.6t, certain accounting approvals, and for other relief; and
- Case No. U-21224: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief.

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

A. The purpose of my direct testimony is to support the Generation Department (“Generation”) requests in this case, and to provide other information that the Company has committed to provide. Toward that end I will:

- Describe Consumers Energy’s coal-, oil-, and gas-fired generation assets, and its hydroelectric and renewable generation assets, including their projected retirement dates;
- Support the Company’s generation asset strategy to: (1) focus continued investment in those generating units (Zeeland Generating Station (“Zeeland Plant”), New Covert Generating Facility (“Covert Plant”), and Jackson Generating Station (“Jackson Plant”)) which provide the most long-term economic benefit for customers; and (2) sustain safe and environmentally compliant operations for its coal generating units (J.H. Campbell (“Campbell”) Units 1, 2, and 3 and D.E. Karn (“Karn”) Units 1 and 2) through their retirement dates;

RICHARD T. BLUMENSTOCK
DIRECT TESTIMONY

- Support the periodic outage plans and the Generation Unit Availability and Random Outage Rate (“ROR”) projections for coal generation, oil- and gas-fired peaking generation, and certain hydroelectric power generation, for the projected test year ending February 28, 2025;
- Support the reasonableness and prudence of the capital expenditures for coal generation, oil- and gas-fired peaking generation, and certain hydroelectric power generation for the historical test year ended December 31, 2022, the 14-month bridge period beginning January 1, 2023 and ending February 29, 2024, and the projected test year ending February 28, 2025;
- Support the reasonableness and prudence of the projected investment for Company-owned Solar Generation for the historical test year ended December 31, 2022, the 14-month bridge period beginning January 1, 2023 and ending February 29, 2024, and the projected test year ending February 28, 2025;
- Support the reasonableness and prudence of the Operation and Maintenance (“O&M”) and fuel handling expenses for coal generation, oil- and gas-fired peaking generation, and hydroelectric power for historical test year ended December 31, 2022, the 14-month bridge period beginning January 1, 2023 and ending February 29, 2024, and the projected test year ending February 28, 2025;
- Support the reasonableness and prudence of the O&M expenses for the Karn Units 1 and 2 retention and separation incentives for the historical test year ended December 31, 2022, the 14-month bridge period beginning January 1, 2023 and ending February 29, 2024, and the projected test year ending February 28, 2025;
- Support the reasonableness and prudence of the O&M expenses for the Campbell Units 1, 2, and 3 retention and separation incentives for the 14-month bridge period beginning January 1, 2023 and ending February 29, 2024, and the projected test year ending February 28, 2025; and
- Describe the environmental regulations with which the Company’s electric generating fleet must comply.

Q. How is your direct testimony related to the direct testimony of other Company witnesses?

A. Company witness Megan L. Metz’s testimony supports the PSCR costs planned to be incurred, taking into account the periodic outages identified in Exhibit A-39 (RTB-1) and the generating unit availability projections in Exhibit A-40 (RTB-2). Company witness

RICHARD T. BLUMENSTOCK
DIRECT TESTIMONY

Metz also supports the capacity value of the Company's generation assets for the seasonal construct in the MISO Planning Resource Auction ("PRA") in Table 2.

Company witness Thomas P. Clark supports the IRP competitive solicitation process and timeline associated with the IRP solar initiative investment, including the build transfer agreements ("BTAs") and their associated projected capital expenditures.

Company witness Adam J. Monroe supports capital investments in river hydroelectric facilities, including the Hardy Dam.

Company witness Josnelly C. Aponte supports the creation of a regulatory asset for the recovery of retention and separation expenses at both the Karn and Campbell sites in her direct testimony.

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

A. Yes, I am sponsoring the following exhibits:

Exhibit A-39 (RTB-1)	Generating Unit Periodic Outages;

Exhibit A-40 (RTB-2)	Generating Unit Availability Projections;

Exhibit A-12 (RTB-3)	Schedule B-5.1	Summary of Actual and Projected Electric Capital Expenditures for the Years 2022 through February 2025; and

Exhibit A-41 (RTB-4)	Summary of the Generation O&M Expense for the Years 2022 through February 2025.

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

A. Yes.

Q. How are the following sections of your direct testimony organized?

A. My direct testimony is divided into four sections. Section I will present exhibits and supporting testimony on the Company's generating assets, its generating asset strategy, and

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1 its generating asset projected performance metrics. Section II will describe the
2 environmental regulations with which the Company's electric generating fleet must
3 comply. Section III presents exhibits and supporting testimony for the historical and
4 projected generation capital expenditures. Section IV will present exhibits and supporting
5 testimony for the historical and projected generation O&M expense. This section will
6 include support of the reasonableness and prudence of the O&M expenses for both the
7 Karn Units 1 and 2 retention and separation incentives and also the reasonableness and
8 prudence of the O&M expenses for Campbell Units 1, 2, and 3 retention and separation
9 incentives.

SECTION I

GENERATION ASSETS

12 **Q. Please provide an overview of the Company's generation assets.**

13 A. As of December 21, 2022, the Company's total projected owned generation assets for the
14 2023/2024 Planning Year had a Generator Verification Test Capacity ("GVTC") of
15 6,647 MW, comprised of the following units:

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TABLE 1

RESOURCE	MICHIGAN LOCATION	IN-SERVICE DATE	RETIREMENT DATE	NET GENERATING CAPABILITY (MW)
COAL FIRED				
JH Campbell 1	West Olive, MI	1962	2025	260
JH Campbell 2	West Olive, MI	1967	2025	350
JH Campbell 3*	West Olive, MI	1980	2025	784 (owned share)
OIL OR GAS FIRED				
Covert	Covert, MI	2004	2040	1089
DE Karn 3	Essexville, MI	1975	2031	298
DE Karn 4	Essexville, MI	1977	2031	592
Zeeland CC	Zeeland, MI	2002	2041	532
Zeeland 1A	Zeeland, MI	2002	2041	159
Zeeland 1B	Zeeland, MI	2002	2041	159
Jackson	Jackson, MI	2002	2041	535
HYDROELECTRIC				
Alcona	Alcona County, MI	1924	n/a	3
Allegan	Allegan County, MI	1936	n/a	1
Cooke	Iosco County, MI	1911	n/a	7
Croton	Newaygo County, MI	1907	n/a	2
Five Channels	Iosco County, MI	1912	n/a	6
Foote	Iosco County, MI	1918	n/a	3
Hardy	Newaygo County, MI	1931	n/a	32
Hodenpyl	Wexford County, MI	1925	n/a	5
Loud	Iosco County, MI	1913	n/a	5
Mio	Oscoda County, MI	1916	n/a	2
Rogers	Mecosta County, MI	1906	n/a	3
Tippy	Manistee County, MI	1918	n/a	6
Webber	Ionia County, MI	1907	n/a	1
RENEWABLES				
Lake Winds	Mason County, MI	2012	2042	101
Cross Winds (Phase I)	Tuscola County, MI	2014	2044	231
Cross Winds (Phase II)	Tuscola County, MI	2018	2048	
Cross Winds (Phase III)	Tuscola County, MI	2018	2048	
Crescent Wind	Jonesville, MI	2021	2051	166
Gratiot Farms Wind	Alma, MI	2021	2051	150
Solar Gardens- GVSU	Grand Rapids, MI	2016	2046	3
Solar Gardens- WMU	Kalamazoo, MI	2016	2046	1
Cadillac Solar Garden	Cadillac, MI	2021	2051	0.5
Circuit West	Grand Rapids, MI	2019	2049	0.5
ENERGY STORAGE				
Ludington Units 1-6**	Ludington, MI	1973	2069	1160 (owned share)

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1 **Q. What does “owned share” mean when used with respect to Campbell Unit 3?**

2 A. The Company owns approximately 93% of Campbell Unit 3. Michigan Public Power
3 Agency and Wolverine Power Supply Cooperative, Inc. own the remaining 7%. Thus, the
4 784 MW capacity reported is 93% of the Campbell Unit 3 GVTC, reflecting the Company’s
5 share of ownership.

6 **Q. What does “owned share” mean when used with respect to Ludington Pumped
7 Storage Plant (“LPS” or “Ludington”) Units 1 through 6?**

8 A. The Company owns 51% of LPS and DTE Electric Company (“DTE”) owns the remaining
9 49%. Thus, the 1,160 MW capacity reported is 51% of the total LPS GVTC, reflecting the
10 Company’s share of ownership.

11 **Q. Do any of the Company’s owned generation units reflect retirement dates which are
12 different from those sponsored in the Company’s previous electric rate case, Case No.
13 U-21224?**

14 A. Yes. The retirement dates for Karn Units 3 and 4 reflect different retirement dates. The
15 Company filed its 2021 IRP in Case No. U-21090 on June 30, 2021 and in its Proposed
16 Course of Action (“PCA”), the Company proposed the retirement of Karn Units 3 and 4
17 by May 31, 2023, coincident with the retirement of Karn Units 1 and 2. However, the
18 Settlement Agreement reached in the 2021 IRP reflected continued operation of Karn Units
19 3 and 4 through May 31, 2031. In addition, the Covert Plant was not reflected in the
20 Company’s owned generating units in Case No. U-21224 but will be included in the
21 Company’s generating resources effective June 1, 2023, as will be discussed in more detail
22 later in this direct testimony. Finally, Karn Units 1 and 2 have been removed due to their
23 pending retirement.

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1 **Q. How will the Company continue to meet its load requirements with the retirement of**
2 **the Campbell units in 2025?**

3 A. The Settlement Agreement approved in the Company's 2021 IRP reflects the replacement
4 of the Campbell unit capacity through a number of different resources including continued
5 growth of its solar generation assets, demand response, energy waste reduction, the
6 acquisition of the Covert Plant by June 1, 2023, continued operation of Karn Units 3 and
7 4, and the addition of 700 Zonal Resource Credits ("ZRCs") by June 1, 2025, through a
8 one-time solicitation approved as part of the Settlement Agreement.

9 The Covert Plant is a 1,089 MW natural gas-fired combined cycle generating unit
10 in Van Buren County. The addition of Covert, 700 ZRCs through a one-time solicitation,
11 continued operation of Karn Units 3 and 4, along with Consumers Energy's current natural
12 gas-fired power plants in Zeeland and Jackson — will meet Michigan's energy needs when
13 renewables and other sources are not available.

14 **GENERATION ASSET STRATEGY**

15 **Q. Please describe the Company's asset strategy for its generating units.**

16 A. The Company's generation asset strategy is focused on providing safe, reliable, regulatory
17 compliant, and economic energy and capacity for its customers. This strategy will be
18 implemented within the construct of the Company's clean energy goals and its IRPs, as
19 approved by the MPSC.

20 **Q. How does the Company's generation asset strategy apply to the Company's various**
21 **generating units?**

22 A. Consistent with Consumers Energy's strategy, the Company's generating asset investments
23 will focus on those generating assets that provide the most economic benefit to customers

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1 through their energy and capacity value in the respective MISO markets. In addition, the
2 Company will also ensure it complies with all state and federal regulations. A detailed
3 discussion of River Hydro compliance is discussed in the direct testimony of Company
4 witness Monroe.

5 Consistent with the approval of the Company's PCA in its 2021 IRP, the Company
6 will concentrate investment on the gas-fired units as they will provide the greatest
7 long-term customer benefit. The coal-fired units will have less investment as they
8 approach retirement. During 2022, the Company's Zeeland and Jackson Plants produced
9 over 27% of the energy value and over 25% of the capacity value realized by the
10 Consumers Energy generating fleet (excluding renewables). The addition of the Covert
11 Plant on June 1, 2023 will significantly increase the energy and capacity value for the
12 Company's gas-fired generation. As such, the Company's investment focus and associated
13 performance projections, have been correspondingly set for these generating units.

14 **Q. How does the Company's generation asset strategy apply to the balance of the**
15 **Company's generating units?**

16 **A.** The Company's generation asset strategy with respect to the remaining generating units
17 will vary depending on each unit's energy value, capacity value and, consistent with the
18 Company's currently approved IRP expected retirement dates. The Company will continue
19 to maintain its generating units, including the River Hydros, to ensure safe and
20 environmentally compliant operations. With the exception of the River Hydros, I will
21 provide additional detail regarding the Company's generation asset strategy for each of the
22 generating units, or group of generating units, in the portion of this direct testimony

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describing projected generating unit availability. Company witness Monroe will provide additional detail regarding the Company's generation asset strategy for the River Hydros.

**PERIODIC OUTAGE PLANS, AVAILABILITY, ROR PROJECTIONS,
AND NET ENERGY VALUE**

Q. Please describe Exhibit A-39 (RTB-1).

A. Exhibit A-39 (RTB-1) identifies the major outages (28 days or longer in duration) that are scheduled during the projected test year ending February 28, 2025, for the Company's fossil-fueled and Ludington Generating Units. The Company's generation asset strategy is a key input to the scheduling of planned outages and outage duration directly informs the periodic factors ("PFs") reflected on Exhibit A-40 (RTB-2).

Q. Please describe Exhibit A-40 (RTB-2), Generating Unit Availability Projections.

A. Exhibit A-40 (RTB-2) details Generating Unit Availability Projections for Consumers Energy's coal generation, peaking generation, and hydraulic power generation for the projected test year beginning March 1, 2024 and ending February 28, 2025. Column (a) identifies Consumers Energy's generating units or category of generating units. Column (b) identifies the five-year historical ROR of the generating unit or category of generating unit. Column (c) identifies the projected ROR of the unit or category of generating unit. Column (d) identifies the PF of the generating unit or category of generating unit. Column (e) identifies the projected availability of the generating unit or category of generating unit. Column (f) identifies the five-year historical Net Energy Value ("NEV") of the generating unit or category of generating unit.

Q. Please define ROR.

A. ROR is a measure of the percent of MWh unavailability due to forced or unplanned generating unit outages and forced or unplanned generating unit de-rates.

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1 **Q. What factors cause an increase or decrease in ROR?**

2 A. The frequency and/or duration of a forced or unplanned generating unit outage or
3 generating unit de-rate directly affects ROR. Reducing the frequency and/or duration of
4 forced or unplanned generating unit outages and generating unit de-rates decreases ROR.
5 Conversely, increasing the frequency and/or duration of forced or unplanned generating
6 unit outages and generating unit de-rates degrades ROR.

7 **Q. How are ROR projections for the Generating units developed?**

8 A. The ROR projections for the projected test year ending February 28, 2025 were developed
9 from the five-year (2018-2022) average. These five-year averages were then adjusted to
10 reflect current operating conditions and projected unit investment. The projected unit
11 investment is developed in accordance with the Company's generation asset strategy.
12 These five-year historical ROR average values are presented in Exhibit A-40 (RTB-2),
13 column (b).

14 **Q. Please define PF.**

15 A. PF is a measure of the percent of lost availability that results from planned outages, planned
16 outage extensions, planned de-rates, and planned de-rate extensions. Planned derates can
17 be taken for a variety of reasons, including the performance of necessary maintenance work
18 which does not require an outage to perform, or the combustion of a coal blend with a
19 lower heat content than is required to achieve the net demonstrated capability of the unit.

20 **Q. What strategy does the Company employ to minimize the impact of planned outages**
21 **on its customers?**

22 A. Consistent with the Company's generation asset strategy, the Company endeavors to
23 schedule planned generating unit outages during periods in which the margin between the

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1 generating unit production cost and the projected MISO energy market price is lowest.
2 This strategy results in creating greater NEV as I will discuss in more detail later in this
3 direct testimony. In general, the projected MISO energy market pricing is lower in the
4 shoulder months of spring and fall due to historically lower demand. However, with the
5 introduction of seasonal capacity in the MISO market, the Company will also consider the
6 impact of outage scheduling on capacity accreditation for the four capacity seasons.
7 Company witness Metz describes seasonal capacity in more detail in her testimony.

8 **Q. Does this outage scheduling strategy apply to all of the Company's generating units?**

9 A. No. For those generating units which have higher production costs and, as a result, are less
10 likely to be dispatched, the available window for scheduling generating unit outages is
11 much larger. The specific strategy for each generating unit or category of generating units
12 will be discussed in more detail later in this testimony.

13 **Q. Please define Projected Availability.**

14 A. Projected Availability is a measure of the percent of time that a generating unit or category
15 of generating units is projected to be available to generate electricity.

16 **Q. How is Projected Availability determined for each generating unit or category of**
17 **generating units?**

18 A. The Projected Availability for each generating unit or category of generating unit is a
19 simple combination of the PF and the projected ROR. Projected Availability is the key
20 performance metric for implementation of the Company's generation asset strategy for
21 each generating unit or category of generating unit.

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1 **Q. How does the Company's generation asset strategy inform Projected Availability?**

2 A. As I previously discussed, our generation asset strategy and associated generation
3 investment will focus on each unit's ability to provide economic value to customers
4 through the unit's ability to produce energy and capacity value in the respective MISO
5 markets. As such, those generating units or category of generating unit providing the
6 greatest amount of economic value to customers will be targeted to achieve the highest
7 projected availabilities.

8 **Q. How can the Company impact Projected Availability for a generating unit?**

9 A. The Company can directly impact Projected Availability for a generating unit by
10 minimizing both PF and ROR for that unit. With respect to minimizing PF, the Company
11 can employ incremental resources during a planned outage to ensure that the critical path
12 for the outage is as short as possible. This strategy could include working 24-hours, seven
13 days a week, for the duration of the outage. Similarly, when a unit experiences an
14 unplanned outage, the Company can employ necessary resources to ensure the unit is
15 returned to available status as quickly as practical. In addition to minimizing unforced
16 outage length, the Company could invest in a generating unit to increase its reliability and,
17 as a result, decrease the generating unit's projected ROR.

18 **Q. Does the Company attempt to maximize availability for all its generating units or**
19 **category of generating units?**

20 A. No. Consistent with the Company's generation asset strategy, the Company focuses on
21 sustaining availability for those generating units which provide the greatest economic
22 benefit to customers through the energy value provided. The Company's generating units
23 get dispatched by MISO as part of the MISO energy market. Based upon the Company's

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1 projected dispatch likelihood for each unit, the Company will rank the generating units
2 from highest economic value to least economic value, and manage the PF and the ROR,
3 and therefore the unit's Availability, to allow for the highest customer value. Or, stated
4 differently, the PF and ROR values may be allowed to be higher (lower unit Availability)
5 for the lower economic value units, and will be managed to lower values (higher unit
6 Availability) for higher economic value units.

7 **Q. How does the Availability projection reflect the customer benefit?**

8 A. An improvement in Availability can translate to a customer benefit in several ways. The
9 immediate benefit is that the generating unit or the category of generating unit is available
10 for dispatch for a greater number of hours throughout the year, likely leading to increased
11 generation, and consequently higher NEV, on an annual basis. Additionally, higher
12 availability increases the ZRCs, increasing the capacity value of the unit.

13 **Q. How does the Company measure the customer benefit resulting from increased**
14 **generation?**

15 A. The Company utilizes NEV to quantify this customer benefit. At a high level, NEV of a
16 generating unit is the difference between the market value of energy and the cost of
17 producing and supplying that energy. NEV is the net customer benefit of a generator's
18 energy production expressed in dollars. These values are presented in Exhibit A-40
19 (RTB-2), column (f), which identifies five-year (2018-2022) actual NEV amounts.

20 **Q. What can the Company do to positively affect NEV?**

21 A. Typically, economic investments that improve the reliability and availability of the
22 generating unit or category of unit will result in increasing NEV. Economic investments
23 that result in a reduction in the cost to generate will also result in increasing NEV, all else

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1 being equal. Positive NEV increases when a generating unit operates more frequently
2 during periods in which market pricing exceeds the cost of production for that unit.
3 Historically, market pricing has tended to be higher in the summer and winter, although
4 there is variability to market conditions. As discussed earlier in my testimony, this is the
5 reason that periodic outages are generally scheduled in the shoulder months of spring and
6 fall. Market prices are typically lower during this time period, thereby reducing the PSCR
7 impact of each scheduled outage.

8 **Q. Does the cost of production vary for the Company's generating units?**

9 A. Yes. The basis for the Company's generation asset strategy is directly related to this
10 actuality. The Company's investment strategy is focused on those units with the lowest
11 variable production costs to maximize NEV for our customers. As the Company
12 strategically invests additional funds in a generating unit to increase its reliability, the
13 expectation is for the generating unit's reliability to be higher than otherwise possible
14 absent the investment. Higher reliability, in turn, increases the likelihood the unit is
15 available during periods when market prices exceed the production cost of the unit, thus
16 increasing the NEV of the unit.

17 **Q. Why is the measurement of NEV important to the Company and its customers?**

18 A. Positive NEV reflects a direct and immediate reduction to customer power supply costs
19 and consideration of NEV provides a basis for making operational and financial decisions
20 in order to maximize the customer value of the generating unit.

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1 **Q. What is another measure the Company uses to evaluate economic projects for its**
2 **generating units?**

3 A. In addition to measuring NEV for a generating unit, the Company also considers the impact
4 a higher availability (specifically ROR) will have on the amount of capacity available from
5 a particular generating unit which receives a monetary credit in the MISO Resource
6 Adequacy Market. Table 2 below summarizes the capacity value of the Company's
7 generating units in the 2022-2023 PRA for Zone 7. Company witness Metz discusses the
8 capacity value of the Company's generating units in the PRA in her testimony in this case.
9 I will discuss the projected impact of the Company's generation asset strategy and
10 associated capital expenditures and major maintenance on the projected availabilities,
11 NEV, and capacity value for each of the generating units later in this direct testimony.

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TABLE 2

RESOURCE	MICHIGAN LOCATION	MISO ISAC ¹ MW	MISO SUMMER SAC ² MW (ZRCs)	CAPACITY VALUE ZONE 7 (SETTLEMENT) ³	CAPACITY VALUE ZONE 7 (75% CONE) ⁴
COAL FIRED					
JH Campbell 1	West Olive, MI	260	245.3	\$ 21,189,235	\$ 15,891,926
JH Campbell 2	West Olive, MI	350	271.6	\$ 23,461,052	\$ 17,595,789
JH Campbell 3	West Olive, MI	784.4 (owned share)	663.5	\$ 57,313,727	\$ 42,985,295
OIL OR GAS FIRED					
Covert	Covert, MI	1088.6	1058.5	\$ 91,434,183	\$ 68,575,637
DE Karn 3	Essexville, MI	298	207.1	\$ 17,889,484	\$ 13,417,113
DE Karn 4	Essexville, MI	591.9	394.5	\$ 34,077,265	\$ 25,557,949
Zeeland CC	Zeeland, MI	532.1	522.1	\$ 45,099,468	\$ 33,824,601
Zeeland 1A	Zeeland, MI	159.4	168.1	\$ 14,520,629	\$ 10,890,472
Zeeland 1B	Zeeland, MI	158.8	167.5	\$ 14,468,801	\$ 10,851,601
Jackson	Jackson, MI	535.3	539.8	\$ 46,628,410	\$ 34,971,307
HYDROELECTRIC					
Alcona	Alcona County, MI	3	3	\$ 259,143	\$ 194,357
Allegan	Allegan County, MI	1.1	1.1	\$ 95,019	\$ 71,264
Cooke	Iosco County, MI	7.1	6.8	\$ 587,390	\$ 440,543
Croton	Newaygo County, MI	2.3	2.3	\$ 198,676	\$ 149,007
Five Channels	Iosco County, MI	6.3	6.1	\$ 526,923	\$ 395,193
Foote	Iosco County, MI	2.9	3	\$ 259,143	\$ 194,357
Hardy	Newaygo County, MI	32.4	31.5	\$ 2,720,998	\$ 2,040,749
Hodenpyl	Wexford County, MI	4.5	4.5	\$ 388,714	\$ 291,536
Loud	Iosco County, MI	4.9	4.7	\$ 405,990	\$ 304,493
Mio	Oscoda County, MI	1.7	1.8	\$ 155,486	\$ 116,614
Rogers	Mecosta County, MI	2.3	2.4	\$ 207,314	\$ 155,486
Tippy	Manistee County, MI	6.2	6.2	\$ 535,562	\$ 401,671
Webber	Ionia County, MI	1	1	\$ 86,381	\$ 64,786
RENEWABLES					
Lake Winds	Mason County, MI	100.8	13.3	\$ 1,148,866	\$ 861,649
Cross Winds (Phase I)	Tuscola County, MI	110.98	15.8	\$ 1,364,818	\$ 1,023,614
Cross Winds (Phase II)	Tuscola County, MI	43.7	6.2	\$ 535,562	\$ 401,671
Cross Winds (Phase III)	Tuscola County, MI	75.9	10.8	\$ 932,914	\$ 699,685
Crescent Wind	Jonesville, MI	166	7.6	\$ 656,495	\$ 492,371
Gratiot Farms Wind	Alma, MI	150	9.7	\$ 837,895	\$ 628,421
Solar Gardens- GVSU	Grand Rapids, MI	3	1.7	\$ 146,848	\$ 110,136
Solar Gardens- WMU	Kalamazoo, MI	1	0.6	\$ 51,829	\$ 38,871
Cadillac Solar Garden	Cadillac, MI	0.5	0.3	\$ 25,914	\$ 19,436
Circuit West	Grand Rapids, MI	0.5	0.3	\$ 25,914	\$ 19,436
ENERGY STORAGE					
Ludington Units 1-6	Ludington, MI	1159.6 (owned share)	1117.2	\$ 96,504,741	\$ 72,378,556
1 ISAC = Intermediate seasonal accredited capacity					
2 SAC = Seasonal accredited capacity and is converted from ISAC based upon offered availability during RA and non-RA hours					
3 2022-2023 PRA Settlement price of \$236.66/MW-day for Zone 7.					
4 2022-2023 PRA 75% CONE price of \$177.50/MW-day for Zone 7.					

1 **Q. Please provide an overview of the generation asset strategy for Campbell**
2 **Units 1 and 2.**

3 **A.** The strategic plan for Campbell Units 1 and 2 is predicated on their planned retirement on
4 May 31, 2025, as reflected in the Company's 2021 IRP Settlement Agreement. The overall
5 remaining life objective for Campbell Units 1 and 2 is to maintain economic dispatch and
6 capacity value from the customer's perspective. The capital expenditures and major

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1 maintenance expenses in the plan are targeted to provide safe and regulatory compliant
2 units. Critical reliability investments required to keep the units available will be included
3 in the plan. Projects that are targeted to improve reliability will not be considered.

4 **Q. How will the Company's generation asset strategy for Campbell Units 1 and 2 impact**
5 **their projected performance?**

6 A. It is anticipated that the unit performance will degrade from current performance for both
7 Campbell Units 1 and 2, and this risk will be accepted to limit new investment as the units
8 near retirement. Based upon the Campbell Units 1 and 2 capital and major maintenance
9 projects that I will discuss later in this direct testimony, the Company's generation asset
10 strategy is expected to result in an ROR of 16.00% at Campbell Unit 1 and 14.50% at
11 Campbell Unit 2 in the test year, as shown on Exhibit A-40 (RTB-2), lines 1 and 2,
12 column (c). During the five-year historical period from 2018 through 2022, Campbell Unit
13 1 had an ROR of 15.56% and Campbell Unit 2 had an ROR of 17.33% as shown on Exhibit
14 A-40 (RTB-2), lines 1 and 2, column (b).

15 **Q. How is this strategy reflected in the Projected Availability for Campbell Units 1 and**
16 **2 in the test year?**

17 A. The Projected Availabilities for Campbell Units 1 and 2 in the test year are 78.23% and
18 70.12%, respectively, as shown on Exhibit A-40 (RTB-2), lines 1 and 2, column (e). The
19 Projected Availability for Campbell Unit 1 reflects a projected ROR of 16.00% and a PF
20 of 6.87%, as shown on Exhibit A-40 (RTB-2), line 1, columns (c) and (d). The planned
21 Campbell Unit 1 outage for the test year is scheduled to begin on October 11, 2024 and last
22 for 25 days. Projected Availability for Campbell Unit 2 reflects a projected ROR of
23 14.50% and a PF of 17.99%, as shown on Exhibit A-40 (RTB-2), line 2, columns (c) and

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(d). The planned Campbell Unit 2 outage for the test year is scheduled to begin on April 1, 2024 and last for 30 days, as reflected on Exhibit A-39 (RTB-1), line 3. These outages are scheduled during periods in which energy prices are projected to be lower, thereby reducing the impact of the outages on customers.

Q. How does the availability for Campbell Units 1 and 2 translate into customer value?

A. As reflected on Exhibit A-40 (RTB-2), lines 1 and 2, column (f), during the five-year historical period from 2018 through 2022, Campbell Unit 1 had an NEV of \$96.8 million and Campbell Unit 2 had an NEV of \$89.6 million. The 2022 NEV for each of these units was \$54.0 million and \$61.6 million for Campbell Units 1 and 2, respectively.

Q. Please quantify the capacity value for Campbell Units 1 and 2.

A. As reflected in Table 2, the capacity value based upon the settlement price for Zone 7 in the 2022-2023 PRA is \$21.2 million for Campbell Unit 1 and \$23.5 million for Campbell Unit 2. The hypothetical capacity value upon which the Company plans its capacity resources (75% of Cost of New Entry ("CONE") for Zone 7 in the 2022-2023 PRA is \$15.9 million for Campbell Unit 1 and \$17.6 million for Campbell Unit 2.

Q. Please provide an overview of the generation asset strategy for Campbell Unit 3.

A. The strategic plan for Campbell Unit 3 is predicated on its planned retirement on May 31, 2025 as reflected in the Company's 2021 IRP Settlement Agreement. The overall remaining life objective for Campbell Unit 3 is to maintain economic dispatch and capacity value from the customer's perspective. The capital expenditures and major maintenance expenses in the plan are targeted to provide safe and regulatory compliant units. Critical reliability investments required to keep the units available will be included in the plan. Capital projects that are targeted to improve reliability will not be considered.

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1 **Q. How will the Company's generation asset strategy for Campbell Unit 3 impact its**
2 **projected performance?**

3 A. It is anticipated that unit performance will remain relatively consistent with current
4 performance. Based upon the Campbell Unit 3 capital and major maintenance projects
5 discussed later in this testimony, the Company's generation asset strategy is expected to
6 result in an ROR of 8.00% at Campbell Unit 3 in the projected test year, as shown on
7 Exhibit A-40 (RTB-2), line 3, column (c). During the five-year historical period from 2018
8 through 2022, Campbell Unit 3 had an actual ROR of 11.70%, as shown on Exhibit A-40
9 (RTB-2), line 3, column (b).

10 **Q. How is this strategy reflected in the Projected Availability for Campbell Unit 3 in the**
11 **test year?**

12 A. The Projected Availability for Campbell Unit 3 in the test year is 84.44%, as shown on
13 Exhibit A-40 (RTB-2), line 3, column (e). This Availability for Campbell Unit 3 reflects
14 a projected ROR of 8.00% and a PF of 8.22%, as shown on Exhibit A-40 (RTB-2), line 3,
15 columns (c) and (d). The planned outage for the test year is scheduled to begin on April 16,
16 2024 and last for 30 days, as reflected on Exhibit A-39 (RTB-1), line 4. The outage is
17 scheduled during a period in which energy prices are projected to be lower, thereby
18 reducing the impact of the outage on customers.

19 **Q. How does the Campbell Unit 3 Availability translate into customer value?**

20 A. As reflected on Exhibit A-40 (RTB-2), line 3, column (f), during the five-year historical
21 period from 2018 through 2022, Campbell Unit 3 had an NEV of \$365.3 million. The 2022
22 NEV for Campbell Unit 3 was \$190.2 million.

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1 **Q. Please quantify the capacity value for Campbell Unit 3.**

2 A. As reflected in Table 2, the Campbell Unit 3 capacity value based upon the settlement price
3 for Zone 7 in the 2022-2023 PRA is \$57.3 million and the Campbell Unit 3 hypothetical
4 capacity value based upon 75% of CONE for Zone 7 in the 2022-2023 PRA is
5 \$43.0 million.

6 **Q. Please provide an overview of the generation asset strategy for Karn Units 1 and 2.**

7 A. The strategic plan for Karn Units 1 and 2 is predicated on their planned retirement on
8 May 31, 2023 as documented in the Company's approved Settlement Agreement in the
9 Company's 2018 IRP, Case No. U-20165. The overall remaining life objective for Karn
10 Units 1 and 2 is to maintain economic dispatch from the customer's perspective. Economic
11 O&M expenses through retirement on May 31, 2023, are targeted to maintain operable,
12 safe, and regulatory compliant units through their retirement date. No capital expenditures
13 are included in the plan.

14 **Q. Please provide an overview of the generation asset strategy for Karn Units 3 and 4.**

15 A. The strategic plan for Karn Units 3 and 4 is predicated on their planned retirement on
16 May 31, 2031 as reflected in the Company's 2021 IRP Settlement Agreement. The overall
17 remaining life objective for Karn Units 3 and 4 is to maintain economic dispatch and
18 capacity value from the customer's perspective. The capital expenditures and major
19 maintenance expenses in the plan are targeted to provide safe and regulatory compliant
20 units. Critical reliability investments required to keep the units available will be included
21 in the plan. Projects that are targeted to improve reliability will not be considered.

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1 **Q. How will the Company's generation asset strategy for Karn Units 3 and 4 impact their**
2 **projected performance?**

3 A. It is anticipated that unit performance for Karn Units 3 and 4 will slightly degrade from
4 current performance. Based upon the Karn Units 3 and 4 capital and major maintenance
5 projects that I will discuss later in this direct testimony, the Company's generation asset
6 strategy is expected to result in an ROR of 16.50% at Karn Unit 3 and 17.50% at Karn
7 Unit 4 in the test year, as shown on Exhibit A-40 (RTB-2), lines 4 and 5, column (c).
8 During the five-year historical period from 2018 through 2022, Karn Unit 3 had an ROR
9 of 36.05% and Karn Unit 4 had an ROR of 29.51%, as shown on Exhibit A-40 (RTB-2),
10 lines 4 and 5, column (b).

11 **Q. How is this strategy reflected in the Projected Availability for Karn Units 3 and 4 in**
12 **the test year?**

13 A. The projected availabilities for Karn Units 3 and 4 in the test year are 61.02% and 73.90%,
14 respectively, as shown on Exhibit A-40 (RTB-2), lines 4 and 5, column (e). The
15 availability for Karn Unit 3 reflects a projected ROR of 16.50% and a PF of 26.92%, as
16 shown on Exhibit A-40 (RTB-2), line 4, columns (c) and (d). The planned outage for the
17 test year is scheduled to begin on March 1, 2024 and last for 43 days, as reflected on Exhibit
18 A-39 (RTB-1), line 1. The availability for Karn Unit 4 reflects a projected ROR of 17.50%
19 and a PF of 10.43%, as shown on Exhibit A-40 (RTB-2), line 5, columns (c) and (d). The
20 planned outage for the test year is scheduled to begin on March 31, 2024 and last for
21 38 days, as reflected on Exhibit A-39 (RTB-1), line 2.

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1 **Q. How does the Projected Availability for Karn Units 3 and 4 translate into customer**
2 **value?**

3 A. As reflected on Exhibit A-40 (RTB-2), lines 4 and 5, column (f), during the five-year
4 historical period from 2018 through 2022, Karn Unit 3 had a NEV of -\$8.1 million and
5 Karn Unit 4 had a NEV of -\$11.1 million. The 2022 NEV for each of these units
6 was -\$0.9 million and -\$4.1 million for Karn Units 3 and 4, respectively.

7 **Q. Please explain why the NEVs for Karn Units 3 and 4 are negative.**

8 A. The NEVs for Karn Units 3 and 4 are negative for several reasons, including the need to
9 perform unit demonstration testing, unit performance, and conduct operator training. Due
10 to the production cost for the units, the units get dispatched far less than the Company's
11 other generating assets. In order to minimize the impact of the required operation of the
12 units, the Company performs those activities during periods in which operation is most
13 economic. However, despite the fact that the NEVs are slightly negative, the units provide
14 a significant amount of value in the form of relatively cheap capacity, which far outweighs
15 the negative NEV values. In addition, the Company's ability to have these units dispatched
16 during tight generation days provides reliability benefits for the Company's customers and
17 the MISO energy market.

18 **Q. Please quantify the capacity value for Karn Units 3 and 4.**

19 A. As reflected in Table 2, the capacity value based upon the settlement price for Zone 7 in
20 the 2022-2023 PRA is \$17.9 million for Karn Unit 3 and \$34.1 million for Karn Unit 4.
21 The hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2022-2023
22 PRA is \$13.4 million for Karn Unit 3 and \$25.6 million for Karn Unit 4.

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1 **Q. Please provide an overview of the generation asset strategy for the Zeeland Plant.**

2 A. The strategic plan for the Zeeland Plant is predicated on plant operation through Planning
3 Year 2040. The overall long-term objective for the Zeeland Plant is to maintain economic
4 dispatch and capacity from the customer's perspective. The units provide significant value
5 to customers in both the energy and resource adequacy markets. The capital expenditures
6 and major maintenance expenses in the plan are targeted to provide a safe, regulatory
7 compliant, and reliable unit. Critical reliability investments required to keep the units
8 available will be included in the plan. Projects that are targeted to improve reliability will
9 be included in the plan if they provide value to customers.

10 **Q. How will the Company's generation asset strategy for the Zeeland Plant impact its**
11 **projected performance?**

12 A. It is anticipated that site performance will remain relatively consistent with current
13 performance. Based upon the Zeeland Plant capital and major maintenance projects that I
14 will discuss later in this testimony, the Company's generation asset strategy is expected to
15 result in an ROR of 4.0% at the Zeeland Plant in the test year, as shown on Exhibit A-40
16 (RTB-2), lines 13 through 15, column (c). During the five-year historical period from 2018
17 through 2022, the Zeeland Plant had ROR values at or below 4.77% for all units, as shown
18 on Exhibit A-40 (RTB-2), lines 13 through 15, column (b).

19 **Q. How is this strategy reflected in the Projected Availability for the Zeeland Plant in**
20 **the test year?**

21 A. The Projected Availability for the combined cycle generating units (Units 1 and 2) at the
22 Zeeland Plant in the test year is 90.79%, as shown on Exhibit A-40 (RTB-2), line 13,
23 column (e). The Zeeland combined cycle (Units 3, 4, and 5) generating unit availability is

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1 based upon a projected ROR of 4.0% and a PF of 5.43%, as shown on Exhibit A-40
2 (RTB-2), line 13, columns (c) and (d). The Projected Availabilities for the simple cycle
3 generating units at the Zeeland site in the projected test year are 93.73% and 92.75%,
4 respectively, as shown on Exhibit A-40 (RTB-2), lines 14 and 15, column (e). The Zeeland
5 simple cycle generating unit Projected Availabilities are based upon projected RORs of
6 4.0% and PFs of 2.36% and 3.39%, respectively, as shown on Exhibit A-40 (RTB-2),
7 lines 14 and 15, columns (c) and (d). There are no outages greater than 28 days scheduled
8 for the Zeeland combined cycle units (Units 3, 4, and 5) in the projected test year ending
9 February 28, 2025, however there are several shorter duration outages of 10 days each
10 scheduled in May and October. There are also no outages greater than 28 days scheduled
11 for the Zeeland simple cycle units (Units 1 and 2) however several shorter planned outages
12 are scheduled for those units in April and May 2024, lasting a total of nine days for Unit 1
13 and 13 days for Unit 2. These outages are scheduled during periods in which energy prices
14 are projected to be lower, thereby reducing the impact of the outages on customers.

15 **Q. How does the Zeeland Plant Projected Availability translate into customer value?**

16 A. As reflected on Exhibit A-40 (RTB-2), lines 13 through 15, column (f), during the five-year
17 historical period from 2018 through 2022, the Zeeland Plant provided a total NEV of
18 \$197.3 million. The 2022 NEV for Zeeland was \$89.0 million.

19 **Q. Please quantify the capacity value for the Zeeland Plant.**

20 A. As reflected in Table 2, the Zeeland Plant capacity value based upon the settlement price
21 for Zone 7 in the 2022-2023 PRA is \$74.1 million and the Zeeland Plant hypothetical
22 capacity value based upon 75% of CONE for Zone 7 in the 2022-2023 PRA is
23 \$55.6 million.

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1 **Q. Please provide an overview of the generation asset strategy for the Jackson Plant.**

2 A. The strategic plan for the Jackson Plant is predicated on plant operation through Planning
3 Year 2040. The overall long-term objective for the Jackson Plant is to maintain economic
4 dispatch and capacity from the customer's perspective. The units provide significant value
5 to customers in both the energy and resource adequacy markets. The capital expenditures
6 and major maintenance expenses in the plan are targeted to provide a safe, regulatory
7 compliant, and reliable unit. Critical reliability investments required to keep the units
8 available will be included in the plan. Projects that are targeted to improve reliability will
9 be included in the plan if they provide value to customers.

10 **Q. How will the Company's generation asset strategy for the Jackson Plant impact its**
11 **projected performance?**

12 A. It is anticipated that site performance will remain relatively consistent with current
13 performance. Based upon the Jackson Plant capital and major maintenance projects that I
14 will discuss later in this direct testimony, the Company's generation asset strategy is
15 expected to result in an ROR of 4.50% at the Jackson Plant in the test year, as shown on
16 Exhibit A-40 (RTB-2), line 16, column (c). During the five-year historical period from
17 2018 through 2022, the Jackson Plant had an actual ROR of 6.38%, as shown on Exhibit
18 A-40 (RTB-2), line 16, column (b).

19 **Q. How is this strategy reflected in the Projected Availability for the Jackson Plant in**
20 **the test year?**

21 A. The Projected Availability for all of the generating units at the Jackson site in the test year
22 is 91.25%, as shown on Exhibit A-40 (RTB-2), line 16, column (e). The Projected
23 Availability for the Jackson site reflects a projected ROR of 4.50% and a PF of 4.45%, as

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1 shown on Exhibit A-40 (RTB-2), line 16, columns (c) and (d). There are no major planned
2 outages in excess of 28 days for the Jackson units in the test year, however a short 12-day
3 outage is scheduled to begin September 29, 2024. In addition, several derates are scheduled
4 to perform inspections and maintenance on various generating units in April and September
5 2024.

6 **Q. How does the Jackson Plant Projected Availability translate into customer value?**

7 A. As reflected on Exhibit A-40 (RTB-2), line 16, column (f), during the five-year historical
8 period from 2018 through 2022, the Jackson units provided a total NEV of \$152.0 million.
9 The 2022 NEV for the Jackson Plant was \$74.2 million.

10 **Q. Please quantify the capacity value for the Jackson Plant.**

11 A. As reflected in Table 2, the Jackson Plant capacity value based upon the settlement price
12 for Zone 7 in the 2022-2023 PRA is \$46.6 million and the Jackson Plant hypothetical
13 capacity value based upon 75% of CONE for Zone 7 in the 2022-2023 PRA is
14 \$35.0 million.

15 **Q. How will the Company's generation asset strategy for the Covert Plant impact its
16 projected performance?**

17 A. It is anticipated that site performance will remain relatively consistent with past
18 performance under different ownership. Based upon the Covert Plant capital and major
19 maintenance projects that I will discuss later in this direct testimony, the Company's
20 generation asset strategy is expected to result in an ROR of 0.96% to 1.74% at the Covert
21 Plant in the test year, as shown on Exhibit A-40 (RTB 2), lines 17 through 19, column (c).

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1 **Q. How is this strategy reflected in the Projected Availability for the Covert Plant in the**
2 **test year?**

3 A. The Projected Availability for each of the combined cycle generating units at the Covert
4 Plant in the test year ranges from 93.07% to 93.81%, as shown on Exhibit A-40 (RTB-2),
5 lines 17 through 19, column (e). The Covert combined cycle generating unit availability
6 is based upon projected ROR of 0.96% to 1.74% and a PF of 5.28%, as shown on Exhibit
7 A-40 (RTB-2), lines 17 through 19, columns (c) and (d). There are no outages greater than
8 28 days scheduled for the Covert Plant combined cycle units (Units 1, 2, and 3) in the
9 projected test year ending February 28, 2025, however there is a shorter duration outage of
10 19 days scheduled for each unit. These outages are scheduled for October and November
11 2024, periods in which energy prices are projected to be lower, thereby reducing the impact
12 of the outages on customers.

13 **Q. How will the Covert Plant Projected Availability translate into customer value?**

14 A. The Company projects that the Covert Plant combined cycle units will provide NEV that
15 is approximately twice that of the Jackson and Zeeland Combined Cycle Units.

16 **Q. Please quantify the capacity value for the Covert Plant.**

17 A. As reflected in Table 2, the Covert Plant capacity value based upon the settlement price for
18 Zone 7 in the 2022-2023 PRA is \$91.4 million and the Covert Plant hypothetical capacity
19 value based upon 75% of CONE for Zone 7 in the 2022-2023 PRA is \$68.6 million.

20 **Q. Please provide an overview of the generation asset strategy for the River Hydro units.**

21 A. A full discussion of the Company's River Hydro generation asset strategy is included in
22 the direct testimony of Company witness Monroe.

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1 **Q. Please provide an overview of the generation asset strategy for Ludington.**

2 A. The strategic plan for Ludington is predicated on retiring the units by July 30, 2069. The
3 Company has recently completed a major overhaul of the Ludington units which is
4 intended to provide increased capacity and generation, increased efficiency, and an
5 extended service life which directly supported the 50-year Federal Energy Regulatory
6 Commission ("FERC") license extension. The value for these units resides primarily in
7 the resource adequacy market (capacity market) with the ability to generate power rather
8 instantaneously when electric energy prices are high, or pump power rather instantaneously
9 when electric energy prices are low. The overall long-term objective for Ludington is to
10 maintain reliable reserve capacity for customers. The capital expenditures and major
11 maintenance expenses in the plan are targeted to increase unit capacity and efficiency and
12 provide safe and regulatory compliant units. Critical reliability investments required to
13 keep the units available will be included in the plan. Projects that are targeted to improve
14 reliability will be considered if they provide significant value to customers. Ludington is
15 also a FERC-regulated hydroelectric facility for which dam safety investments are
16 identified and initiated as a result of regulatory compliance and adherence to FERC
17 processes, including the FERC Part 12 process discussed in Mr. Monroe's direct testimony.

18 **Q. How will the Company's generation asset strategy for Ludington impact its projected**
19 **performance?**

20 A. It is anticipated that Ludington performance will remain relatively consistent with current
21 performance through the projected test year. Based upon the Ludington capital and major
22 maintenance projects that I will discuss later in this direct testimony, as well as the
23 Ludington unit major overhauls performed over the past eight years, the Company's

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1 generation asset strategy is expected to result in an ROR of 4.00% for the Ludington units
2 in the test year, as shown on Exhibit A-40 (RTB-2), lines 6 through 11, column (c). During
3 the five-year historical period from 2018 through 2022, the Ludington units had average
4 ROR values ranging from 1.70% to 9.30%, as shown on Exhibit A-40 (RTB-2), lines 6
5 through 11, column (b).

6 **Q. How do the Ludington Pumped Storage Units factor into the Company's future**
7 **renewable energy strategy as outlined in the IRP?**

8 A. Given the intermittent nature of solar and wind generation and the Company's plans to
9 move to a zero net carbon future, Ludington is becoming a more critical component of the
10 Company's generation portfolio. Ludington can deliver a significant amount of energy in
11 a short time period; providing energy supply from the reservoir during periods when the
12 wind doesn't blow and/or the sun doesn't shine. Additionally, when there is an
13 over-abundance of wind and/or solar generation, Ludington can utilize the excess energy
14 to fill the reservoir. Ludington's large energy storage capability greatly enables the
15 transition to renewable energy.

16 **Q. How is this strategy reflected in the Projected Availability for Ludington in the test**
17 **year?**

18 A. The Projected Availabilities for all of the Ludington units in the projected test year ranges
19 from 79.52% to 87.44%, as shown on Exhibit A-40 (RTB-2), lines 6 through 11,
20 column (e). The Projected Availabilities for the Ludington generating units reflect a
21 projected ROR of 4.00% and PFs ranging from 8.92% to 17.17%, as shown on Exhibit
22 A-40 (RTB-2), lines 6 through 11, columns (c) and (d). There are two major outages
23 planned for the Ludington units that will begin in the test year; Ludington Units 3 and 4

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1 each have an outage scheduled to begin on February 10, 2025 and last 120 days, as reflected
2 on Exhibit A-39 (RTB-1), lines 6 and 7. In addition, shorter outages on all six Ludington
3 units are scheduled throughout the test period. The outages are scheduled during periods
4 in which the likelihood of Ludington unit dispatch is lower, thereby reducing the impact of
5 the outages on customers.

6 **Q. How does the Ludington Unit Projected Availability translate into customer value?**

7 A. As reflected on Exhibit A-40 (RTB-2), lines 6 through 11, column (f), during the five-year
8 historical period from 2018 through 2022, the Ludington units provided a total NEV of
9 \$32.8 million. The 2022 NEV for Ludington was \$23.8 million.

10 **Q. Please quantify the capacity value for Ludington.**

11 A. As reflected in Table 2, the Ludington capacity value based upon the settlement price for
12 Zone 7 in the 2022-2023 PRA is \$96.5 million and the Ludington hypothetical capacity
13 value based upon 75% of CONE for Zone 7 in the 2022-2023 PRA is \$72.4 million.

14 **Q. Please provide an overview of the generation asset strategy for the Renewable Energy**
15 **Assets.**

16 A. The Company's strategic plan for Renewable Energy Assets, both wind and solar, is
17 entirely driven by the Company's MPSC-approved 2021 IRP Settlement Agreement.
18 Consistent with the IRP, the strategy for the wind assets is to complete construction and
19 have all wind assets in service in 2024 with the completion of Heartland Wind Farm. With
20 respect to solar, the Company plans to continue to add incremental solar resources in
21 accordance with its Clean Energy Plan and Renewable Energy Plan. These solar resources
22 are being added pursuant to the Company's 2018 IRP and 2021 IRP annual solicitations,
23 as discussed in more detail later in this direct testimony. In addition, the Company

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1 anticipates that it will also add up to 1,000 MW of wind and solar assets through 2027¹ in
2 support of the Company's voluntary green pricing program and their costs will be
3 reconciled through the Company's renewable energy plan. The overall investment
4 objective for the Company-owned assets is to provide funding for projects as appropriate
5 to maintain economic dispatch and capacity from the customer's perspective. The
6 Company has an energy-based availability target of 91% for its renewable energy wind
7 assets. This availability target considers those periods during which the wind is sufficient
8 to produce energy. The capital expenditures and major maintenance expenses in the plan
9 are targeted to maintain the designed performance level.

10 **Q. How do the Company's renewable assets translate into customer value?**

11 A. Similar to the Company's Hydro units, the production cost of the Company's renewable
12 energy assets is zero. As such, all energy sold into the MISO energy market has value
13 provided that the MISO locational marginal prices are positive. As reflected on Exhibit
14 A-40 (RTB-2), lines 20 through 21, column (f), during the four-year historical period from
15 2019 through 2022, the Cross Winds Energy Park and the Lake Winds Energy Park
16 provided a total NEV of \$141.1 million. The 2022 NEVs for Cross Winds Energy Park
17 and Lake Winds Energy Park were \$43.1 million and \$15.4 million, respectively. As
18 reflected on Exhibit A-40 (RTB-2), lines 22 through 23, column (f), the 2022 NEVs for
19 Gratiot Farms Wind and Crescent Wind were \$24.7 million and \$23.4 million, respectively.
20 The Company began to measure the NEV for its solar assets in 2020 and the 2020 through
21 2022 NEV for its Solar Garden Assets totaled \$914,786.

¹ The Settlement Agreement in the Company's 2021 Renewable Energy Plan Amendment, Case No. U-20984, reflected the addition of up to 500 MW of solar and 500 MW of wind over the period from 2024 through 2027 to support the Company's Large Customer Renewable Energy Program.

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1 **Q. Please quantify the capacity value for renewable energy assets.**

2 A. As reflected in Table 2, the renewable asset capacity value based upon the settlement price
3 for Zone 7 in the 2022-2023 PRA is \$5.7 million and the renewable asset hypothetical
4 capacity value based upon 75% of CONE for Zone 7 in the 2022-2023 PRA is \$4.3 million.

5 **Q. Why have you included a hypothetical capacity value for each of the generating units**
6 **or category of generating units?**

7 A. I have included these hypothetical values to reflect the capacity values that the Company
8 uses in its capacity planning process. Company witness Metz provides additional
9 information regarding the capacity value of the Company's generation assets in MISO's
10 PRA as well as the projected capacity margin in future years for Zone 7.

11 **Q. How will the Company determine the reasonableness and prudence of additional**
12 **investments in the generating fleet?**

13 A. Additional investment in the remaining units over and above those necessary to maintain
14 safety and regulatory compliance would require some level of economic benefit for
15 customers, otherwise the investment does not make sense. The generating unit periodic
16 outage plans, projected RORs and, ultimately, projected availability for each generating
17 unit or category of generating units reflects the Company's generation asset strategy.

18 **SECTION II**
19 **ENVIRONMENTAL REGULATIONS**
20 **OVERVIEW**

21 **Q. Can you please list the environmental regulations with which Consumers Energy is**
22 **required to comply and that are relevant to expenditures for which the Company is**
23 **seeking recovery in this case?**

24 A. Yes. The Company's fossil-fueled Electric Generating Units ("EGUs") are subject to
25 numerous complex and overlapping air, water, and waste regulations.

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Current (On-going) Environmental Compliance

Environmental Regulations – Air Quality

Q. Describe Consumers Energy’s Existing Air Quality Compliance Strategy (“AQCS”).

A. Over the past decade, Consumers Energy has had expenditures to comply with a variety of air quality-related regulations, including the Cross State Air Pollution Rule, the Mercury and Air Toxics Standards, and the Michigan Mercury Rule, among others. The background and purpose of each such rule has been discussed in the testimony of prior rate cases, including Case No. U-17735. To comply with these regulations, Consumers Energy created the AQCS. Cost recovery reflecting the Company’s AQCS was approved in the November 19, 2015 Order in the Company’s 2014 Electric Rate Case No. U-17735. This AQCS has prudently ensured compliance with applicable state and federal air-quality related regulations. The Company’s actions and investments to achieve such compliance have been performed in a manner which has minimized, to the extent reasonably possible, the associated costs for customers. The investments made to ensure environmental compliance have allowed the continued operation of coal generation while the Company transitions to carbon-free generation sources like solar.

Q. Are there any updates to the air quality-related regulations for which the Company’s existing AQCS complies with?

A. Yes. In April, 2022 the Environmental Protection Agency (“EPA”) proposed the “Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard.” If the rule is finalized as proposed, prior to the conclusion of the 2023 ozone season, then there is the potential for an increase of expenses in either the form of purchased nitrogen oxide (“NO_x”) allowances, additional reagent for the NO_x

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1 control equipment and/or a combination of the two. The Company will continue to monitor
2 the progress of the proposed rule and evaluate the various options for compliance with the
3 rule.

4 **Q. What are the capital investments and/or O&M expenses the Company is seeking**
5 **recovery of in this case that are specifically related to air quality control?**

6 A. Any capital and/or O&M required for the operation of the air quality control systems that
7 the Company is seeking recovery can be found in Exhibit A-12 (RTB-3), Schedule B-5.1.

8 **Q. Are you seeking recovery of any expenses related to the regulation of greenhouse**
9 **gases from EGUs?**

10 A. No, not at this time. On June 19, 2019, the EPA finalized three rulemakings related to the
11 regulation of greenhouse gases, specifically carbon dioxide, from EGUs: (i) repeal of the
12 Clean Power Plan; (ii) issuance of the final Affordable Clean Energy (“ACE”) Rule and;
13 (iii) issuance of new Clean Air Act (“CAA”) Section 111(d) regulations. This rule was
14 subsequently overturned in litigation, and the EPA issued the final Good Neighbor Plan on
15 March 15, 2023. The Good Neighbor Plan requires reductions in oxides of nitrogen
16 emissions from power plants and industrial facilities for 23 states, including Michigan. The
17 Company is in the process of evaluating the impacts of the Good Neighbor Plan on its fossil
18 generating units.

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Environmental Regulations and Compliance Strategy – Waste

1
2 **Q. Can you please describe the relevant parts of the Resource Conservation and**
3 **Recovery Act (“RCRA”) as related to Coal Combustion Residuals (“CCR”)**
4 **management?**

5 A. On April 17, 2015, the EPA published 40 CFR Parts 257 and 261, Disposal of CCRs from
6 Electric Utilities, in the Federal Register under Subtitle D of the RCRA. The rules establish
7 minimum national criteria for purposes of determining which CCR solid waste disposal
8 facilities and solid waste management practices pose a reasonable probability of adverse
9 effect on health or the environment under RCRA. The rule is considered
10 self-implementing, meaning that affected facilities must certify compliance with the
11 published standards and schedules. By codifying standards under Subtitle D, Owners and
12 Operators are not required to obtain permits, and states are not required to adopt and
13 implement the new rules. Instead, the rules’ only enforcement mechanism is for a state or
14 citizen group to bring a RCRA citizen suit in federal district court against any facility that
15 is alleged to be in noncompliance with the newly promulgated minimum standards. In
16 December 2016, the Water Infrastructure Improvements for the Nation (“WIIN”) Act was
17 passed. This bill provides authority for state implementation of coal ash management
18 through a state permit program in lieu of the current enforcement of the CCR Rule through
19 the RCRA Citizen Suit Authority. States may elect to submit a CCR permit program to
20 the EPA for approval. The State of Michigan revised its solid waste statute in late 2018 to
21 outline a state CCR permitting program. Michigan has submitted its application to the EPA
22 for a permit program and is awaiting the EPAs review of administrative completeness. In

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1 the interim, the EPA has enforcement authority over the RCRA-CCR Rule as provided in
2 the WIIN Act.

3 The existence of a state permitting program allows Department of Environment,
4 Great Lakes, and Energy ("EGLE") to issue permits under Michigan's solid waste
5 management statute (Part 115 of the Natural Resources and Protection Act of 1994
6 ("NREPA"), as amended) to regulate compliance schedules and activities for CCR landfills
7 and surface impoundments. Although the current state CCR permitting program was
8 passed into law and Consumers Energy is obligated to comply with the associated statute,
9 permits, and licenses, the program must be approved by the EPA on the basis that it is "as
10 protective as" the CCR Rule to avoid dual state and federal regulation. Thus, similar
11 compliance standards are required within the state permitting program, including
12 requirements to make compliance documentation publicly available, completing the work,
13 and then self-reporting by providing notifications to EGLE and posting to a publicly
14 accessible compliance website.

15 **Q. What are the capital and/or O&M investments Consumers Energy is seeking**
16 **recovery of in this case that are specifically related to RCRA compliance and/or**
17 **overall CCR Management?**

18 A. The Company's CCR management compliance strategy was approved in Case No.
19 U-18322. The major capital work for compliance has been completed. The capital and/or
20 O&M required for the management of CCRs under the RCRA that the Company is seeking
21 recovery of can be found in Exhibits A-12 (RTB-3), Schedule B-5.1, and A-41 (RTB-4).
22 Separately, there are closure activities that will continue throughout the test year and
23 beyond; however, those expenses are Cost of Removal and are not included in this filing.

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SECTION III
GENERATION CAPITAL EXPENDITURES
OVERVIEW

1
2
3
4 **Q. What factors does the Company consider in determining the capital investments that**
5 **it will make at its generating plants?**

6 A. The major drivers in the determination of generation capital investments are plant safety,
7 compliance with regulations, and reliability. Consumers Energy's strategy for complying
8 with environmental regulations was previously discussed in this direct testimony.

9 **Q. Please describe Exhibit A-12 (RTB-3), Schedule B-5.1, Generation Capital**
10 **Expenditures.**

11 A. This exhibit presents the capital expenditures for Generation, 2022 through the projected
12 test year - 12 months ending February 28, 2025. Exhibit A-12 (RTB-3), Schedule B-5.1,
13 is a 10-page exhibit. Page 1 of this exhibit presents a summary of Generation capital
14 expenditures for the Historical Period ended December 31, 2022, the Projected 14-month
15 Bridge Period beginning January 1, 2023 and ending February 29, 2024, and the projected
16 test year beginning March 1, 2024 and ending February 28, 2025. This summary
17 information is broken down by Steam Power Generation, Hydraulic Power Generation,
18 Pumped Storage Generation, and Other Production Plant. Pages 2 through 5 of this exhibit
19 capture the same Historical Year, Bridge Period, and Test Year Generation capital
20 expenditures information, but is presented by generating sites and environmental
21 categories. This information is further detailed by Contractor, Labor, Materials, Business
22 Expenses, Contingency, and Other. Page 6 of this exhibit represents a summary of pages 2
23 through 5 of this exhibit. Page 7 of this exhibit provides a summary of Non-Environmental
24 and All Other Environmental capital expenditures in the Projected 14-month Bridge Period
25 ending February 29, 2024 and the projected test year ending February 28, 2025. Finally,

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pages 8 through 10 of this exhibit identify the capital projects and associated expenditures that are greater than \$1 million that contribute to the overall capital expenditures summarized on pages 1 through 7 of this exhibit. Specifically, page 8 of this exhibit presents capital projects for the Historical Period ended December 31, 2022; page 9 of this exhibit presents capital projects for the Projected 14-month Bridge Period beginning January 1, 2023 and ending February 29, 2024; and page 10 of this exhibit presents capital projects for the projected test year ending February 28, 2025.

Q. What project information is presented on Exhibit A-12 (RTB-3), Schedule B-5.1, pages 8 through 10?

A. Exhibit A-12 (RTB-3), Schedule B-5.1, pages 8 through 10, presents the generation type, the generation unit, project type, project classification, class of cost estimate, engineering type, internal or external engineering, project bid issued, budget approval², project description, and project cost information. The project type identifies whether the project is routine or non-routine. Routine projects include work that is performed regularly whereas non-routine projects are typically undertaken once every 10 years or longer. The class of cost estimate reflects the Association for the Advancement of Cost Engineering (“AACE”) class of the project cost estimate, the engineering type denotes whether the engineering was performed internally or by a third-party engineering firm, the project bid reflects the status of the project bids, and the budget approval reflects the status of internal approval for the project, including projected cost amount.

Exhibit A-12 (RTB-3), Schedule B-5.1, page 8, does not include information for class of cost estimate, engineering type, internal or external engineering, and project bid issued.

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Q. What cost information is included on Exhibit A-12 (RTB-3), Schedule B-5.1, pages 8 through 10?

A. Exhibit A-12 (RTB-3), Schedule B-5.1, page 8, includes actual capital project cost, projected contingency, and projected total cost. The projected contingency, if applicable, and projected total cost, were included in Case No. U-21224. Exhibit A-12 (RTB-3), Schedule B-5.1, pages 9 and 10, included the project planned amount, contingency amount, project cost reduction, and projected amount. The project planned amounts were reduced by project reductions and contingency to arrive at the projected amounts.

Q. Please explain the project reduction amount.

A. The projects presented on page 9 of Exhibit A-12 (RTB-3), Schedule B-5.1, reflect a project reduction amount of \$6.597 million.

Q. What level of capital spending for generating plants does the Company request the Commission to incorporate into rates in this case?

A. The Company's rate relief request in this case reflects capital spending on projects for its generating plants of \$141.372 million for the historical test year ended December 31, 2022 as shown on Exhibit A-12 (RTB-3), Schedule B-5.1, page 1, line 17, column (b); \$1,370,168³ million in the projected 14-month Bridge Period ending February 29, 2024 as shown on Exhibit A-12 (RTB-3), Schedule B-5.1, page 1, line 17, column (e); and \$387.888 million in the projected test year ending February 28, 2025 as shown on Exhibit A-12 (RTB-3), Schedule B-5.1, page 1, line 17, column (f).

³ The \$815 million acquisition of the Covert Plant accounts for a majority of the capital expenditures in the bridge period.

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1 **Q. Please explain how the Company prioritizes its capital investments within**
2 **Generation.**

3 A. In evaluating capital investments, the Company's first priority is addressing safety,
4 regulatory, compliance, and continued operation related projects. These projects are
5 considered a mandatory cost of doing business. Safety, regulatory, compliance, and
6 continued operation-related projects provide economic value to customers in that they
7 allow the units to remain in service and avoid potential derates and/or shutdown due to an
8 intervention by various regulators including Occupational Safety and Health
9 Administration ("OSHA"), the EGLE, the EPA, and FERC. In order to minimize the
10 impact of these projects on customers, the Company utilizes a least cost/best fit ("LCBF")
11 for the investments necessary to satisfy service quality, safety, and Federal and State policy
12 requirements.

13 **Q. How does the Company determine whether other projects get approved for funding?**

14 A. In accordance with the Company's generation asset strategy for each generating unit or
15 category of generating units, economic projects that are expected to reduce ROR,
16 maintenance cost or heat rate, all else being equal, are evaluated to ensure that their
17 implementation results in a net benefit to the customer. For a project to receive approval
18 for implementation, the projected benefits of the work must have a greater value than the
19 cost of implementing the project. In other words, the implementation of the project should,
20 at a minimum, result in a marginal customer benefit.

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1 **Q. How does the Company evaluate other capital investments, such as economic**
2 **projects?**

3 A. The Company uses two financial measures, Internal Rate of Return (“IRR”) and Present
4 Value Ratio (“PVR”), as a means to evaluate and prioritize projected economic projects
5 within Generation. A complex financial model was developed in-house that allows the
6 Company to calculate and measure the numerous changes that result when improvements
7 (both O&M and Capital) are made to its rate-based generating units.

8 **Q. Does the Company calculate IRRs or PVRs for all projects?**

9 A. No. The Company calculates IRRs or PVRs for economic projects that are not considered
10 required but would yield net benefits to customers. Projects required for regulatory,
11 compliance, and/or continued operations are reviewed to assure that the project is cost
12 effective and result from a reasonable evaluation of alternatives, but because the project
13 must be done for compliance and continued operation, IRR or PVR may not be calculated.
14 When evaluating project alternatives related to regulatory, compliance, and/or continued
15 operations, IRRs or PVRs may be used to rank alternatives.

16 **Q. Please explain what you mean by projects for continued operations.**

17 A. Projects for continued operations refers to projects which are necessary to allow the
18 generating unit to continue to operate through its retirement date. Alternatives for projects
19 necessary for continued operation will generally be evaluated based upon LCBF. For this
20 evaluation, one of the alternatives will include a decision to not perform the project and
21 either retire the unit earlier than projected or operate the unit at a permanent derate.

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1 **Q. How does the Company evaluate customer benefits associated with**
2 **generation-related capital investments?**

3 A. The Company uses replacement power cost estimates and PSCR impacts when evaluating
4 customer benefits. The Company also evaluates ROR and heat rate improvements, which
5 result in increased and/or lower cost generation.

6 **Q. How does the Company evaluate historical events which have impacted availability?**

7 A. The cause of each of the historical events impacting availability are evaluated and
8 measured, and the actions necessary to avoid the same or similar events are considered for
9 implementation. In many cases, actions necessary to prevent the event from recurring are
10 cost beneficial. The availability projections, including ROR, simply reflect the Company's
11 best estimate of the operational benefits of those corrective actions that have already been
12 taken or are planned to be taken, through the projected test year ending February 28, 2025.

13 **Q. Does the Company evaluate customer benefits associated with Outage Schedules?**

14 A. Yes, the Company uses historical market prices to evaluate timing around outages, in an
15 effort to ensure the unit is available during periods in which market pricing is projected to
16 be high.

17 **Q. Is it possible that the Company could experience changes to its scheduled outages and**
18 **forecasted capital expenditures in the future?**

19 A. Yes. The Company often forecasts future actions and capital expenditures based on
20 currently available information, many months before the work is completed. To provide
21 some perspective, the outage schedule used in this case was approved in August 2022. A
22 review of the outage schedule used in this case identifies seven scheduled outages that
23 begin in March 2024 (18 months after the schedule was approved) and run through

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1 February 28, 2025, 29 months later. During each of these seven scheduled outages,
2 Consumers Energy has scheduled a number of tasks to be performed. Because of the long
3 lead times, the number of outages scheduled during the test year, and the fact that several
4 different tasks will be performed during each outage, it is inevitable that some scheduled
5 outages and forecast capital expenditures will change. However, the Company has a
6 history of prudent capital investments in its generating facilities, which have been
7 consistently supported by the Commission.

8 **Q. Are there other reasons why outage schedule changes occur?**

9 A. Yes. Some of the reasons why outage schedule changes occur are: contractor availability,
10 parts availability, changes in regulations, design changes, outage scope changes, changes
11 in unit condition, and spot market prices.

12 **Q. Can you provide an example of when circumstances changed?**

13 A. Yes. The Company's fall 2021 outage for Campbell Unit 1 was originally scheduled from
14 September 24, 2021 through November 8, 2021. The outage was deferred to 2022 due to
15 the higher than projected MISO energy prices and the Company's ability to create
16 economic value for its customers through continued operation of the unit. Campbell Unit 1
17 provided more that \$27 million in NEV to customers during 2021, a portion of which was
18 earned during the originally scheduled outage period. The deferred Campbell Unit 1
19 outage began on February 27, 2022 and lasted 39 days, ending April 8, 2022. The outage
20 was taken for air preheater basket and seal replacement, pulse jet fabric filter ("PJFF") bag
21 replacement, performance of high energy piping surveillance ("HEPS"), and flow
22 accelerated corrosion ("FAC") inspection.

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1 **Q. Please describe how the Company determines its generation projected capital**
2 **expenditure amounts.**

3 A. Consistent with the Company's generation asset strategy, generation projected capital
4 investments support the continued safe, regulatory compliant, and reliable operations of
5 the Company's generating fleet. Projected capital investments are informed by historical
6 and anticipated performance of the units. The reasonableness of the generation capital
7 investments is indicated by the sustained or improved performance of the Company's
8 generating fleet relative to: (1) the safety of the employees, contractors, and community at
9 and around the generating facilities; (2) compliance with rules and regulations; and
10 (3) reliably participating in the energy, resource adequacy, and ancillary services markets.

11 **Q. How are projects identified that are discussed later in this direct testimony?**

12 A. Generation System Planners assess the equipment performance and compare that
13 assessment with the generation asset strategy for the generating unit. Upon identification
14 of a potential project, the Planner will complete a project initiation document ("PID"). This
15 document defines the issue, alternatives considered for resolution, intended benefits or
16 consequences avoided, and suggested timing and a cost estimate. The document is
17 reviewed by multiple groups for alignment and ultimately routed for approval for inclusion
18 in the Long Term Financial Plan ("LTFP"). PIDs entered into the LTFP will typically be
19 scheduled three to five years in the future to align with outages and provide the project
20 execution teams ample time to plan and engineer.

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1 **Q. How were the projected capital expenditure amounts developed for each of the**
2 **projects discussed later in this direct testimony?**

3 A. Each project begins with the creation of a PID. The Planner will provide an initial cost
4 estimate for the project within the PID. The Planner utilizes past experience, contractor
5 cost estimates, internal estimates, Original Equipment Manufacturer (“OEM”) data, and
6 studies to provide the best estimate of the costs. This activity typically takes place three to
7 five years prior to the start of project execution.

8 **Q. How are PIDs related to Concept Approval Documents (“CADs”)?**

9 A. The PID is the mechanism utilized to allow projects to be considered for the LTFP. Once
10 the project is included in the LTFP and the project is within a year of start of execution,
11 the CAD is created. The CAD is templated from the PID and updated as necessary. The
12 CAD is then routed for approval to the designated level of management based on project
13 amount and, once approved, the project will be initiated.

14 **Q. Do adjustments to the projected capital investment amounts for each of the projects**
15 **occur prior to project implementation?**

16 A. Yes. As the project team progresses through the life cycle of a project, there are multiple
17 opportunities to better define project costs. Activities such as detailed engineering,
18 bidding, contractor involvement, and construction all allow for budgets to be better defined.
19 As this definition evolves, the projected capital investments are updated accordingly.

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2022 HISTORICAL TEST YEAR CAPITAL EXPENDITURES

1
2 **Q. How does the 2022 actual capital expenditure amount of \$141.372 million compare to**
3 **the amount of capital expenditures reflected in the Company's request in Case No.**
4 **U-21224?**

5 A. The 2022 actual capital expenditure amount of \$141.372 million is \$76.480 million below
6 the Company's requested amount in Case No. U-21224. As is discussed later in this direct
7 testimony, the reduction in the Company's actual capital expenditure amount is directly
8 attributable to spending approximately \$81.4 million less on solar projects than projected.
9 It is important to note that the projected solar project capital expenditures were not
10 projected to close by the end of the projected test year and were offset by the allowance for
11 funds used during construction ("AFUDC"). As such, the underspend did not impact the
12 revenue requirement. The Company's as-filed 2022 projected capital expenditure amount
13 of \$210.910 million was adjusted to \$217.852 million in the Company's rebuttal testimony
14 to remove several projects at the Jackson Plant, as they were no longer required, and add
15 several projects at Karn Units 3 and 4 due to the 2021 IRP settlement agreement which
16 continued the operation of Karn Units 3 and 4 through 2031. A compilation of the 2022
17 projects which have actual capital expenditure amounts greater than \$1 million is presented
18 on Exhibit A-12 (RTB-3), Schedule B-5.1, page 8.

19 **Q. How does the compilation of capital projects on Exhibit A-12 (RTB-3), Schedule**
20 **B-5.1, page 8, compare with the 2022 capital projects reflected on Case No. U-21224,**
21 **Exhibit A-12 (SAH-3), Schedule B-5.7, page 7?**

22 A. A comparison of the projects on Exhibit A-12 (RTB-3), Schedule B-5.1, page 8, with the
23 2022 projects reflected on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7,

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1 page 7, reveals that there are six projects on Exhibit A-12 (RTB-3), Schedule B-5.1, page 8,
2 which were not reflected on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7,
3 page 7. In addition, there were three projects for 2022 that were reflected on Case No.
4 U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 7, that are not presented on Exhibit
5 A-12 (RTB-3), Schedule B-5.1, page 8.

6 **Q. Please discuss the 2022 capital projects that were included on Case No. U-21224,**
7 **Exhibit A-12 (SAH-3), Schedule B-5.7, page 7, that are not presented on Exhibit A-12**
8 **(RTB-3), Schedule B-5.1, page 8.**

9 A. The following projects are not presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 8,
10 due to the fact that their actual 2022 capital expenditure amount was less than \$1 million
11 or the project was not pursued in 2022. The disposition of these capital projects is below:

- 12 • Foote Trash Rack Ergonomics (\$2,675,000). This project began in 2022 at an
13 actual cost of \$793,452. This project is scheduled to be completed in 2024 at a
14 projected cost of \$1,466,667 as discussed in the direct testimony of Company
15 witness Monroe;
- 16 • 2019 IRP Solar Bid Event (\$63,593,000). The actual 2022 capital expenditure
17 was \$162,468. A thorough discussion of this project's status is presented in
18 Company witness Clark's direct testimony; and
- 19 • 2020 IRP Solar Bid Event (\$40,909,000). The actual 2022 capital expenditure
20 was \$147,697. A thorough discussion of this project's status is presented in
21 Company witness Clark's direct testimony.

22 **Q. Please discuss the 2022 capital projects that were not included in Case No. U-21224,**
23 **Exhibit A-12 (SAH-3), Schedule B-5.7, page 7, that are presented on Exhibit A-12**
24 **(RTB-3), Schedule B-5.1, page 8.**

25 A. The disposition of these capital projects is presented below:

- 26 • Campbell Unit 3 Diesel Generator Controls (\$1,172,322). This project was
27 scheduled for 2022 but the project estimate was only \$186,620. The project
28 costs increased because the original estimate did not include the engineering
29 and integration costs. While the Company had anticipated using a single vendor

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to provide that information, the Company ultimately had to hire three separate contractors to accomplish the work. As such, a significant amount of engineering for the load center, the panel, and the generator was required, none of which was reflected in the original estimate. In addition, the project experienced cost increases on both material and labor as the project extended through the COVID pandemic time frame and the supply chain disruptions after that;

- Campbell North and South Pigeon Lake Jetties – Concrete and Fence Replacement (\$1,003,268). This project was scheduled for 2022 but the project estimate was only \$740,000. The project cost increased due to the fact that the work scope increased since the estimate was prepared and also due to the increased cost of materials. The north and south jetties, as well as the paved path just east of the north jetty, have suffered significant damage as a result of the high water on Lake Michigan. The south jetty has further eroded dunes threatening access to the jetty, as well as concrete that is starting to break apart and wash out on the jetty. The north jetty has extensive concrete damaged along its west end due to sand wash out, the chain link fence has been destroyed, and the asphalt path that connects the jetty to the boardwalk has been washed away. The Company needs safe access to the north and south jetties to install lights and conduct other periodic maintenance and the Company is required to provide safe access to the north jetty for recreational opportunities in accordance with its LPS FERC license. This project was completed for compliance and was not avoidable considering the May 31, 2025 retirement of the Campbell site;
- Jackson long term historical extra work (\$3,919,897). This project was scheduled for 2022 but the project estimate was only \$950,000. The actual project cost exceeded the projected cost due to findings (including balance piston, air piston manifold, and bearing housing) during the performance of the major overhaul on engine 191-351, findings during semi-annual borescopic inspections requiring remediation (high pressure compressor blading replacement) to ensure continuous operation of existing, in-service engines, and restoration of the LM6000 engine (191-306), including the high pressure turbine, to a serviceable condition. The long-term service agreement (“LTSA”) historical extra work is defined as the work that is not covered under normal planned maintenance in the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items that need to be addressed are labor and material to replace the following: blading, combustion cans, ignitors, vanes/bushings, and any components on the compressor end as the compressor is not covered under the LTSA;
- Mio Downstream Reverse Filter (\$1,058,458). This project was scheduled for 2022 but the project estimate was only \$570,000. The primary cause of project increase was project bids coming in higher than what was projected in the concept approval for the project. Additional cost increases resulted from wetlands mitigation, change from rip-rap to field stone, and increased loadings.

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This was a dam safety project identified and initiated through FERC's Part 12D process. The scope of this project was to install a reverse granular filter downstream of the left embankment over an area that has historically had seepage and boil activity. This system is designed to act as a filter at the embankment toe, extending the seepage path length and minimizing the potential for fine material transport. A downstream area of the left embankment at Mio Dam has a history of sand boils, which can lead to soil piping and cause the dam to fail. Remediation of the soil piping potential is required to help reduce the risk of PFM 1.1 (Left Embankment Failure due to Internal Erosion through Foundation) from occurring. This project was implemented in concert with the Mio Left Retaining Wall;

- LPS 480V Motor Control Center (\$1,538,171). This project was scheduled for 2022 but the project estimate was only \$845,400. The actual cost of this project increased in 2022 due to the need to expedite the installation of the new Switchgear 5 in 2022 due to the failure of the legacy Switchgear 5 on July 30, 2022 as well as pull forward replacement of the top of dike buried conduit installation. It was determined the site was at risk of not being able to pump/generate should another Switchgear 5 bucket fail. The scope of this project is the replacement of the 20 480V Dike Load Centers ("DLCs") over a six-year period that began in 2020 at a capital expenditure amount of \$0.671 million. The DLCs are original plant equipment and suffer from corrosion and deterioration. The primary purpose of the DLCs is to distribute power to 193 dike drain pumps and 34 pumping relief wells located around the reservoir. The purpose of the dike drain pumps is to keep the upstream face of the dike in a drained condition and to protect the asphalt liner from damage due to differential pressure. The purpose of the pumping relief wells is to keep groundwater at pre-construction levels, thereby minimizing the likelihood of a downstream slope failure. Replacement of the DLCs over a six-year period will provide high electrical system reliability and ensure FERC compliance; and
- 2021 IRP Solar Bid Event – Muskegon Solar Project (\$22,788,539). The projected amount was \$20,332,607 but it was not included in the Company's request for rate relief in Case No. U-21224. The basis for this project is described in the direct testimony of Company witness Clark.

Q. How did the capital expenditure amount for the projects presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 8, compare to the capital expenditure amount for the projects presented on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 7?

A. The total projected capital expenditure for the 2022 projects included on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 7, was \$177.975 million net of

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1 contingency and the total actual capital expenditures for the projects presented on Exhibit
2 A-12 (RTB-3), Schedule B-5.1, page 8, is \$118.365 million, a reduction of \$59.610 million.
3 An evaluation of the 2022 projects included on Case No. U-21224, Exhibit A-12 (SAH-3),
4 Schedule B-5.7, page 7, against the actual costs for those projects reveals that with the
5 exception of projected costs for the 2019 and 2020 solar bid event projects (underspent by
6 more than \$81 million), the reduction in the spend for the Karn unit separation project
7 (\$5.602 million), and the 2021 solar bid event project (overspent by \$22.789 million), the
8 projected spending for the large projects was on target. A discussion of the 2019, 2020,
9 and 2021 solar bid event projects (i.e. the Mustang Mile Solar Project, the Washtenaw
10 Solar Project, and the Muskegon Solar Project) is included in the direct testimony of
11 Company witness Clark.

12 **Q. How did the capital expenditure amount for the projects presented on Exhibit A-12**
13 **(RTB-3), Schedule B-5.1, page 8, impact the 2022 total projected capital expenditure**
14 **amount of \$217.852 million?**

15 A. The \$59.610 million decrease in capital expenditures from the \$177.975 million net of
16 contingency for the projects presented on Case No. U-21224, Exhibit A-12 (SAH-3),
17 Schedule B-5.7, page 7, versus the \$118.365 million for the projects presented on Exhibit
18 A-12 (RTB-3), Schedule B-5.1, page 8, helps explain the difference in the capital
19 expenditure amount of \$217.852 million requested in Case No. U-21224 Exhibit A-225
20 (SAH-7) and the actual 2022 capital expenditure amount \$141.372 million requested in
21 this proceeding. The actual amount spent for the Karn Units 3 and 4 separation project,
22 and the actual amount spent for three Hardy projects (discussed later) makes up a majority
23 of the remaining difference.

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1 **Q. Were there any major 2022 projects whose capital expenditures were contested**
2 **and/or not fully included in the Case No. U-21224 Settlement Agreement?**

3 A. Yes. The 2022 projected capital expenditures for three projects at Hardy, (1) Auxiliary
4 Spillway Replacement, (2) Crest Roadway Replacement and Compaction, and (3) Splash
5 Wall Replacement, were limited to engineering costs only, or \$5.3 million. The total
6 amount reflected in the Company's original request for recovery was \$8.26 million, and
7 the actual 2022 amount for engineering costs totaled \$4.057 million.

8 **Q. Did the Case No. U-21224 Settlement Agreement establish other limitations or**
9 **requirements for the Company's hydroelectric generating facilities?**

10 A. Yes. In addition to the capital expenditure limitation for 2022 as discussed above, the
11 Settlement Agreement limited 2023 cost recovery to projected engineering costs totaling
12 \$3.45 million. Further, the Settlement Agreement required the Company to collaborate
13 with the MPSC Staff and the Attorney General to both scope and conduct various analyses
14 of all reasonable options to remediate the condition of the Hardy Dam, prior to
15 commencing construction of the Hardy Dam upgrades.

16 **Q. What specific analyses will be performed?**

17 A. The analyses will include the development of economic business cases for the Hardy Dam
18 which will consider, at a minimum, the feasibility and impacts of (1) full decommissioning
19 and removal, (2) divestiture, (3) permanently lowering the reservoir height, and (4) any
20 other reasonable options that lead to a reduced impact of the Hardy Dam on customer rates.
21 These economic business cases are required to be performed by an external engineering
22 firm with experience in the engineering, construction and decommissioning of dams.
23 Specifically, the economic business cases will assess the value of the energy and capacity

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1 that Hardy Dam will provide customers, under a variety of reasonable assumptions, against
2 the revenue requirement associated with the projected capital expenditures and O&M
3 expenses through 2034, the end of Hardy Dam's current FERC license term.

4 **Q. Does the Case No. U-21224 Settlement Agreement include other requirements?**

5 A. Yes. The Settlement Agreement also requires the Company to either perform, or cause to
6 be performed, an economic assessment of the impact of the various options on the
7 Muskegon River Hydroelectric Dam communities. In addition, the Settlement Agreement
8 requires the Company to engage in discussions with the affected local communities
9 regarding both the costs and timing of the proposed projects for the Hardy, Croton, and
10 Rogers Dams, and the need for funding, including potential funding mechanisms, from the
11 affected communities. The performance of these discussions with the affected local
12 communities as well as the potential funding from these local communities, must be shared
13 with the Commission prior to commencing construction.

14 **Q. What are the Company's current plans for commencing construction at the Hardy**
15 **Dam?**

16 A. As is discussed in more detail in Company witness Monroe's direct testimony, the
17 Company's current plans are to begin construction in the fall of 2025.

18 **CONTINGENCY**

19 **Q. Has the Company included any contingency in the requested capital expenditures for**
20 **Generation?**

21 A. No. However, Exhibit A-12 (RTB-3), Schedule B-5.1, page 4, line 5, columns (c) and (d),
22 presents \$0.807 million in total contingencies in the 14-month bridge period ending

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February 29, 2024, and \$1.083 million in total contingencies in the projected test year ending February 28, 2025.

Q. Why does the Company present contingencies in its individual project capital expenditure amounts?

A. Budgeting for contingency is an accepted Project Management practice. According to the AACE International, contingency is “An amount added to an estimate to allow for items, conditions, or events for which the state, occurrence, or effect is uncertain and that experience shows will likely result, in aggregate, in additional costs.” Contingency is included in some major project estimates and is expected to be used. It is a real item in a project estimate like any other cost, and as such, should be included as a cost. For these reasons contingency costs are appropriate and should be included in the capital expenditures and, ultimately, rate base in this filing.

Q. Has the Company adjusted its practice for inclusion of contingency in this proceeding?

A. Yes. The Commission has issued multiple orders which did not permit recovery of contingency costs. While the Commission acknowledged that inclusion of contingency costs in project planning may be appropriate, it found that those costs should not be included in rates.

Q. Has the Company included other contingency amounts in its requested capital expenditure amounts?

A. No. While the Company has presented projected contingency amounts of \$0.807 million in the 14-month bridge period ending February 29, 2024, and \$1.083 million in test year the ending February 28, 2025, these amounts have not been included in the total capital

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1 expenditure amounts for which the Company is seeking recovery. Because the Company
2 believes that contingency is a real cost of performing project work, it has presented these
3 amounts in testimony in support of each individual project such that they will align with
4 its concept approval documents. Total contingency is then backed out of capital spending
5 in Exhibit A-12 (RTB-3), Schedule B-5.1, page 1, line 16. Projected capital spending less
6 contingency is then presented on line 17 of this exhibit. The Company is including this
7 capital spending net of contingency in its requested rate relief.

PROJECTED 14-MONTH BRIDGE PERIOD CAPITAL
EXPENDITURES

10 **Q. How does the projected 14-month bridge period capital expenditure of \$1,370 million**
11 **compare to the amount of capital approved by the MPSC in Case No. U-21224 for**
12 **2023?**

13 A. The 14-month bridge period projected capital expenditure amount of \$1,370 million is
14 \$107 million more than the projected test year amount of \$1,263 million requested in the
15 Company's last electric rate Case No. U-21224. The primary contributors to the increase
16 between the 2023 projected test year amount in Case No. U-21224 and the 14-month
17 projected bridge period amount in this case is a \$125 million increase in projected capital
18 expenditures for IRP solar bid events as well as the incremental projected capital
19 expenditure amount of \$81 million for the two-month period ending February 29, 2024, as
20 presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 1, line 17, column (d). A
21 compilation of the 14-month bridge period projects which have projected capital
22 expenditure amounts greater than \$1 million is presented on Exhibit A-12 (RTB-3),
23 Schedule B-5.1, page 9.

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1 **Q. How does the compilation of 14-month bridge period capital projects on Exhibit A-12**
2 **(RTB-3), Schedule B-5.1, page 9, compare with the 2023 capital projects reflected on**
3 **Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 8?**

4 A. A comparison of the 14-month bridge period capital projects on Exhibit A-12 (RTB-3),
5 Schedule B-5.1, page 9, with the 2023 projects reflected on Case No. U-21224, Exhibit A-
6 12 (SAH-3), Schedule B-5.7, page 8, reveals that there are 11 projects on Exhibit A-12
7 (RTB-3), Schedule B-5.1, page 9, which were not reflected on Case No. U-21224, Exhibit
8 A-12 (SAH-3), Schedule B-5.7, page 8. In addition, there were 10 projects for 2023 that
9 were reflected on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 8, that
10 are not presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9.

11 **Q. Please discuss the 2023 capital projects that were included on Case No. U-21224,**
12 **Exhibit A-12 (SAH-3), Schedule B-5.7, page 8, that are not presented on Exhibit A-12**
13 **(RTB-3), Schedule B-5.1, page 9.**

14 A. The following projects are not presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9,
15 due to the fact that the projected bridge period capital expenditure amounts are now less
16 than \$1 million or the project is not being pursued in the bridge period. The disposition of
17 these capital projects is below:

- 18 • Campbell Unit 3 Complete Mill Overhauls (\$1,295,300). The Company
19 reduced the cost of this project to \$552,370 in the 14-month bridge period as
20 part of its capital efficiency efforts which will be discussed in more detail later
21 in this direct testimony. This scope of project will also be discussed in more
22 detail later in this direct testimony;
- 23 • Karn Unit 4 distributed control system and simulator upgrade (\$1,000,000).
24 The projected cost of this project has been reduced by \$100,000 and, as such,
25 is no longer presented on Exhibit A-12 (RTB-3), Schedule B-5.1. The scope of
26 this project is discussed later in this direct testimony;
- 27 • Jackson turbine building temperature control replacement (\$1,321,968). This
28 project was removed in the Company's rebuttal testimony in Case No. U-21244

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1 due to the current condition of the equipment. The Company invested
2 approximately \$100,000 to replace inoperable louvers. As a result of this work,
3 the Company believes that it can invest approximately \$20,000 in major
4 maintenance work on an annual basis to keep the turbine building temperature
5 control system operable, thereby obviating the need for this project at this time.
6 The engineering team will re-evaluate this project in the future to ensure annual
7 maintenance resolves the temperature controlling issue and if it is not sufficient,
8 they will develop a future plan and options;

- 9 • Alcona Risk Informed Decision Making Resolution (\$1,000,000). The
10 projected cost for the bridge period has been reduced to \$0.417 million with
11 \$2.5 million reflected in the projected test year. The scope of project will also
12 be discussed in more detail later in this direct testimony;
- 13 • Alcona Trash Rack Ergonomic Project (\$1,160,000). This project has been
14 deferred beyond the test period;
- 15 • Foote Governor Replacement (\$1,277,000). This project was pulled forward
16 and was completed in 2022 at a total cost of \$697,163;
- 17 • Loud Spillway Hoist Replacement (\$1,043,000). The Company reduced the
18 cost of this project by \$50,000 to \$993,000 in the 14-month bridge period as
19 part of its capital efficiency efforts which will be discussed in more detail later
20 in this direct testimony. The project is now below the threshold for inclusion
21 on this exhibit. The scope of project will also be discussed in more detail later
22 in this direct testimony;
- 23 • Jackson Generator Stator Rewind (\$2,400,000). This project was removed in
24 the Company's rebuttal testimony in Case No. U-21224 due to the current
25 condition of the equipment. An inspection performed in Spring 2022 of a
26 corona repair performed in 2021 showed no signs of degradation that would
27 require a stator rewind to be performed in 2023. Another borescopic inspection
28 will be performed in 2024. Beyond 2024, the OEM's in-situ inspections
29 (including visual inspections) will be performed on their five-year planned
30 frequency;
- 31 • Webber Unit 1 Overhaul & Generator Rewind (\$3,570,000). This project has
32 been deferred to the test period and is discussed in the direct testimony of
33 Company witness Monroe; and
- 34 • Zeeland Generator Gas Turbine Rewind (\$2,675,000). This project was
35 cancelled and replaced with bridge period projects for the field rewinds at
36 Zeeland Units 3 and 4 which are discussed below in the bridge period project
37 additions and supported later in this direct testimony.

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1 **Q. Please identify the 14-month bridge period capital projects that were not included on**
2 **Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 8, that are presented**
3 **on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9.**

4 A. The bridge period capital projects that were not included on Case No. U-21224, Exhibit
5 A-12 (SAH-3), Schedule B-5.7, page 8, include: (1) Karn Units 3 and 4 Tank Farm Storage
6 Tank Heating Line Replacement, (2) Karn Units 3 and 4 Sync Wire Replacement,
7 (3) Zeeland Unit 4 Generator Rotor Field Rewind, (4) Zeeland Unit 3 Field Rewind,
8 (5) Rogers PMF Project, (6) Rogers Unit 4 Generator Rewind, (7) Mio Electrical Safety
9 Project, (8) Webber Left Downstream Spillway Abutment Wall, (9) Ludington Oil Water
10 Separator Replacement, (10) Ludington Distributed Control System (“DCS”) Control
11 Relay Replacement, and (11) 2021 Solar Event - Muskegon Solar Project. The basis for
12 projects 1 through 4, 9, and 10 will be discussed in more detail later in this direct testimony,
13 the basis for projects 5 through 8 will be discussed in the direct testimony of Company
14 witness Monroe, and the basis for project 11 will be discussed in the direct testimony of
15 Company witness Clark.

16 **Q. Is the projected capital expenditure amount of \$1,370 million for the 14-month bridge**
17 **period ending February 29, 2024, on Exhibit A-12 (RTB-3), Schedule B-5.1, page 1,**
18 **column (c), consistent with the Company’s generation asset strategy?**

19 A. Yes. Based upon a review of the projected capital expenditure presentation on Exhibit
20 A-12 (RTB-3), Schedule B-5.1, pages 2 and 3, lines 1 through 119, column (h),
21 \$417.180 million of that capital will fund solar projects pursuant to the Company’s IRP,
22 \$882.950 million of that total capital expenditure amount will be used for the acquisition
23 of the Covert Plant and projects at the Covert, Jackson, and Zeeland plants. Furthermore,

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1 \$13.794 million will fund various projects at the LPS, and \$36.662 million will fund
2 various hydro safety, reliability, and regulatory compliance projects. With the exception
3 of the solar projects and the river hydro projects, a detailed discussion of the various
4 projects for each generating unit or group of generating units will be provided later in this
5 direct testimony. The river hydro projects will be discussed in the direct testimony of
6 Company witness Monroe and the solar projects will be discussed in the direct testimony
7 of Company witness Clark.

8 **Q. Do the Company's projected capital expenditures at the Campbell site for the**
9 **14-month bridge period ending February 29, 2024, align with the Company's**
10 **generation asset strategy and the planned retirement of the generating units at that**
11 **site?**

12 A. Yes. The Company's projected capital expenditures for Campbell Units 1, 2, and 3 for the
13 14-month bridge period ending February 29, 2024 are significantly reduced from the
14 five-year average capital expenditure amount for the period from 2018 through 2022. The
15 14-month bridge period capital expenditures for Campbell Units 1 and 2 represents an 87%
16 reduction from the five-year average, the 14-month bridge period projected capital
17 expenditures for Campbell Unit 3 represents a 50% reduction from the five-year average.

PROJECTED TEST YEAR CAPITAL EXPENDITURES

19 **Q. Is the projected capital expenditure amount of \$387.888 million for the test year**
20 **ending February 28, 2025, on Exhibit A-12 (RTB-3), Schedule B-5.1, page 1,**
21 **column (d), consistent with the Company's generation asset strategy?**

22 A. Yes. Based upon a review of the projected capital expenditure presentation on Exhibit
23 A-12 (RTB-3), Schedule B-5.1, pages 2 and 3, lines 1 through 119, column (j),

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1 \$269.457 million of that capital will fund solar projects pursuant to the Company's IRP
2 and \$47.281 million of that total capital expenditure amount will be used for projects at the
3 Covert, Jackson, and Zeeland plants. Furthermore, \$14.137 million will allow the
4 Company to complete various regulatory, reliability, and infrastructure projects necessary
5 to support the 50-year license extension at Ludington granted by FERC in 2019 and
6 \$49.897 million will fund various hydro safety, reliability, and regulatory compliance
7 projects. Except for the solar projects and the river hydro projects, a detailed discussion of
8 the various projects for each generating unit or group of generating units will be provided
9 later in this direct testimony. The river hydro projects will be discussed in the direct
10 testimony of Company witness Monroe and the solar projects will be discussed in the direct
11 testimony of Company witness Clark.

12 **Q. Do the Company's projected capital expenditures at the Campbell site for the test**
13 **year ending February 28, 2025 align with the Company's generation asset strategy**
14 **and the planned retirement of the generating units at that site?**

15 **A.** Yes. As previously discussed, the Company's projected capital expenditures for Campbell
16 Units 1, 2, and 3 for the test year ending February 28, 2025 are significantly reduced from
17 the five-year average capital expenditure amount for the period from 2018 through 2022.
18 The test year projected capital expenditures for Campbell Units 1 and 2 represents a 98%
19 reduction from the five-year average, the test year projected capital expenditures for
20 Campbell Unit 3 represent a 96% reduction from the five-year average.

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Campbell Units 1 and 2

Q. Please explain the Company's projected capital investment for the 14-month projected bridge period ending February 29, 2024 and projected test year ending February 28, 2025 for Campbell Units 1 and 2.

A. The Company plans to invest a total of \$1.723 million in the 14-month bridge period and \$0.285 million in the test year on Campbell Units 1 and 2. The projected bridge period amount includes \$1.393 million in non-environmental expenditures and \$0.330 million in environmental expenditures and the projected test year amount includes \$0.272 million in non-environmental expenditures and \$0.014 million in environmental expenditures. The non-environmental amounts are shown on both Exhibit A-12 (RTB-3), Schedule B-5.1, page 2, line 1, columns (h) and (j), respectively, and Exhibit A-12 (RTB-3), Schedule B-5.1, page 7, line 1, columns (b) and (d), respectively, and the environmental amounts are shown on Exhibit A-12 (RTB-3), Schedule B-5.1, page 7, line 2, columns (c) and (e), respectively. These capital investments will be facilitated by outages at Campbell Unit 1 in the fall of both 2023 and 2024 and outages at Campbell Unit 2 in the spring of 2023 and 2024. The Campbell Unit 2 outage scheduled for the spring of 2024 is presented on Exhibit A-39 (RTB-1), line 3.

Q. What is the basis for the projected \$1.723 million investment in the projected bridge period?

A. The projected \$1.723 million investment will fund regulatory compliance and reliability projects. There are no projects whose projected cost is greater than \$1 million, but the following projects are important to regulatory compliance and reliability:

- Campbell Unit 1 and Unit 2 Major Motor and Pump Overhauls (\$100,000 per unit). This project will overhaul major motors and/or pumps based on

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established rebuild schedules and equipment condition assessments. Large pumps and motors require overhauls/rewinds on a regular schedule and the work will provide continued equipment reliability through plant retirement on May 31, 2025. Condition assessments of plant equipment are performed on a monthly basis, and it is through that process that the specific pumps and motors requiring overhaul are identified. Upon identification of the specific pumps and motors to be overhauled, unique capital projects are established to perform the work. The performance of this work will maintain unit reliability. This project is being completed for unit reliability and is not considered avoidable;

- Campbell Units 1 and 2 Balance of Plant (“BOP”) Equipment Replacements (\$200,000 per unit). This project will replace various BOP equipment on Campbell Units 1 and 2 in 2023 based upon condition assessments and the work will provide continued equipment reliability through plant retirement on May 31, 2025. This project is being completed for unit reliability and is not considered avoidable;
- Campbell Unit 2 AQCS Projects (\$200,000). This project will complete various AQCS projects at Campbell 2 during the projected bridge period, thereby providing continued equipment reliability and regulatory compliance through plant retirement on May 31, 2025. This project is being completed for air quality regulation compliance and is not considered avoidable;
- Campbell Unit 2 Condensate Pump Overhaul (\$215,000). The Campbell Unit 2A Condensate Pump & Motor each require a capital overhaul. The pump was last overhauled in 2006, and industry standards for large pumps suggest overhauls on a 10-year frequency. Significant wear is expected on the pump components based on previous inspection reports of identical pumps (Campbell Unit 2C Condensate Pump, 2018). The pump is experiencing lost performance due to the extended time between overhauls. The motor was last reconditioned in 2016, and while minimal effort is expected for the motor, it is logical to perform the motor inspection/overhaul at the same time the pump is to be overhauled; and
- There are eight projects which are common to the Campbell site. Based upon a 43% allocation of the cost to Campbell Units 1 and 2 and a 57% cost allocation to Campbell Unit 3, the various 14-month projected bridge period site commons projects include \$0.708 million in projected capital expenditures for Campbell Units 1 and 2. A more detailed discussion of these projects will be provided later in this direct testimony in the discussion of Campbell Site Commons projects.

Q. What is the basis for the projected \$0.285 million investment in the test year?

A. The projected \$0.285 million investment will fund three projects which are common to the Campbell site. This projected amount reflects a 43% allocation of the total amount. A

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1 more detailed discussion of these projects will be provided later in this direct testimony in
2 the discussion of Campbell Site Commons projects.

3 **Campbell Unit 3**

4 **Q. Please explain the Company's projected capital investment for the 14-month**
5 **projected bridge period ending February 29, 2024 and projected test year ending**
6 **February 28, 2025 for Campbell Unit 3.**

7 A. The Company plans to invest a total of \$5.138 million in 14-month projected bridge period
8 and \$0.378 million in the projected test year at Campbell Unit 3. The 14-month projected
9 bridge period amount includes \$2.437 million in non-environmental expenditures and
10 \$2.700 million in environmental expenditures and the projected test year amount includes
11 \$0.360 million in non-environmental expenditures and \$0.018 million in environmental
12 expenditures. The non-environmental amounts are shown on both Exhibit A-12 (RTB-3),
13 Schedule B-5.1, page 2, line 8, columns (h) and (j), respectively, and Exhibit A-12
14 (RTB-3), Schedule B-5.1, page 7, line 3, columns (b) and (d), respectively, and the
15 environmental amounts are shown on Exhibit A-12 (RTB-3), Schedule B-5.1, page 7,
16 line 4, columns (c) and (e), respectively. These capital investments will be facilitated by
17 outages in the spring of both 2023 and 2024. The Campbell Unit 3 outage scheduled for
18 the spring of 2024 is presented on Exhibit A-39 (RTB-1), line 4.

19 **Q. What is the basis for the projected \$5.138 million capital expenditure amount for the**
20 **14-month projected bridge period?**

21 A. The projected \$5.138 million capital expenditure amount will fund regulatory compliance
22 and reliability projects. One of those projects is greater than \$1 million and is presented

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on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, line 1. The basis for this project is described below:

- Campbell Unit 3 – Selective Catalytic Reduction (“SCR”) Catalyst Management (\$2,302,733). The scope of this project is the ongoing management of the SCR catalyst. The performance of this work will maintain the functionality of an environmental related system by removing old, exhausted layers of catalyst and replacing with new layers of plate type catalyst, thereby maintaining the efficiency of the SCR. This project is being completed for air quality regulation compliance and is not considered avoidable considering the unit retirement on May 31, 2025.

The following projects are less than \$1 million each but are important to regulatory compliance and reliability:

- Campbell Unit 3 Complete Mill Overhauls (\$552,370). This project will continue the rebuild of the Campbell Unit 3 Coal Mills which began in 2020 at a projected capital expenditure of \$0.503 million. Coal mills experience wear and degradation over time, resulting in reduced performance and increased reliability risk. Suboptimal performance negatively impacts combustion and efficiency due to increased particle sizes. This project will begin the periodic rebuild of the coal mills for Campbell Unit 3. The performance of this work will maintain the high level of unit availability necessary to provide customer value. This project is being completed for unit reliability and is not considered avoidable considering the unit retirement on May 31, 2025;
- Campbell Unit 3 AQCS Projects (\$225,000). This project will complete various AQCS projects at Campbell Unit 3 during the 14-month projected bridge period, thereby providing continued equipment reliability and regulatory compliance through plant retirement on May 31, 2025. This project is being completed for air quality regulation compliance and is not considered avoidable;
- Campbell Unit 3 CO-O₂ monitor replacement (\$223,944). This project began in 2021 and its scope includes the replacement of the existing O₂ monitors. The ability to monitor post-combustion CO does not currently exist on Campbell Unit 3; the existing monitors only measure oxygen. The inability to adequately measure the flue gas results in poor combustion and increased difficulty in efficiently controlling NO_x. The monitor replacements will be completed in the spring 2023 outage; resulting in increased efficiency and improved environmental monitoring and control. This project is being completed for unit reliability and is not considered avoidable considering the unit retirement on May 31, 2025;

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- Campbell Fuel Handling/Infrastructure Replacements (\$200,000). Due to normal wear, fuel handling equipment requires periodic replacement. Specific equipment will be replaced during the 14-month projected bridge period based on condition. Equipment to be replaced includes conveyor belts, chutes, and other major fuel handling equipment and infrastructure. This project work will result in continued fuel handling reliability through plant retirement on May 31, 2025. This project is being completed for unit reliability and is not considered avoidable considering the plant retirement on May 31, 2025;
- Five additional projects at Campbell Unit 3 totaling \$0.695 million support regulatory compliance and reliability, with each project representing \$230,000 or less in capital expenditures. These projects include replacement of the electrohydraulic controls fluid purification system, balance of plant equipment replacements, major motor and pump overhauls, emergency diesel generator controls replacement, and house service air compressor replacement; and
- “Site Common” Projects Shared with Campbell Units 1 and 2 (\$1,647,239). Projects that affect the entire site are allocated based on the respective size of the units, with Campbell Unit 3 receiving 57% of the expenditures. These projects are discussed below.

Q. Please explain the Site Commons projects.

A. There are eight Site Commons projects in the 14-month projected bridge period with a total dollar amount of \$1.647 million subject to allocation as described above. None of these projects are greater than \$1 million but the following projects are important to regulatory compliance and reliability:

- Campbell Coal Fleet Fuel Handling Dozer Rebuilds (\$537,000). There are Rubber Tire and Track dozers that are used for fueling the plants, pushing coal out to storage, and grooming the coal pile. In order to reliably keep unloading coal and fueling the plants, these dozers routinely need to go through recommended rebuilds to maintain the fleet of dozers in reliable operating conditions. Failure to provide funding for these dozers could result in catastrophic failure of several diesel components in the dozer, which would necessitate the purchase of a new dozer rather than planning for a rebuild. This project is being completed for unit reliability and is not considered avoidable considering the plant retirement on May 31, 2025; and
- Seven additional site common projects at the Campbell site totaling \$1.110 million support safety and reliability, with each project representing \$335,000 or less in expenditures. These projects include replacement of small pumps and motors, replacement of small valves and instrumentation, and Urea Based Ammonia Supply upgrades.

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1 **Q. What is the basis for the projected \$0.378 million investment in 2023?**

2 A. The projected \$0.378 million investment will fund three projects which are common to the
3 Campbell site. This projected amount reflects a 57% allocation of the total amount, which
4 is \$662,918. These projects include fuel handling dust collector bag replacement, dry ash
5 landfill closure, and machine shop replacement. The funding for the machine shop
6 replacement will evaluate and engineer the various alternatives for moving/replacing the
7 existing machine shop at the Campbell site. The machine shop provides timely and
8 cost-effective solutions to parts and equipment needs at the Company's generating
9 facilities.

10 **Covert Plant**

11 **Q. Please explain the Company's projected capital investment for the 14-month**
12 **projected bridge period ending February 29, 2024 and projected test year ending**
13 **February 28, 2025 for Covert.**

14 A. The Company plans to invest a total of \$829.095 million in the 14-month bridge period
15 and \$20.274 million in the test year at the Covert Plant. These capital investments will be
16 facilitated by 19-day outages at Covert Units 1 through 3 in October and November 2024.

17 **Q. Please explain the Company's projected capital investment for the 14-month bridge**
18 **period ending February 29, 2024 for the Covert Plant.**

19 A. The Company plans to invest a total of \$829.095 million in the bridge period on the Covert
20 Plant, as shown on Exhibit A-12 (RTB-3), Schedule B-5.1, page 2, line 43, column (h).

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Q. What is the basis for the projected \$829.095 million capital investment in the 14-month projected bridge period?

A. The projected \$829.095 million capital investment in the projected bridge period will fund four projects, including the acquisition of the Covert Plant. Three of these projects are greater than \$1 million, and are presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, lines 2 through 4. The basis for these three projects is described below:

- Acquisition of the Covert Plant (\$815,000,000). The scope of this project is the acquisition of the Covert Plant on June 1, 2023. This acquisition was fully supported and approved in the Company's 2021 IRP PCA in Case No. U-21090. The Covert Plant is a natural gas-fired, combined cycle power generating facility with a nameplate capacity of 1,175 MW. The Covert Plant is comprised of three, independently dispatchable units, each of which are rated for 392 MW. Each unit is comprised of a combustion turbine generator ("CTG"), heat recovery steam generator ("HRSG"), and steam turbine generator ("STG") in a 1X1 combined cycle configuration;
- Covert Plant LTSA (\$9,760,795). This is the capital portion for Mitsubishi negotiated services that cover the planned normal maintenance of each generating unit. The CTGs are a Mitsubishi model M501G1-Kai, the HRSGs are a Deltak model, and the STGs are Mitsubishi. The projected capital expenditures are based upon variable fees paid to Mitsubishi for maintenance services which are based on an equivalent fired hour ("EFH") basis pursuant to the LTSA. Unlike the GE LTSAs for the Jackson and Zeeland plants, there are no milestone payments associated with the fee structure for the Mitsubishi LTSA. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected pre-mature failures of the equipment. This will help maximize availability and, as a result, optimize customer value for the site. Normal maintenance will ensure the Company continues reliable operation of the units; and
- Covert Plant non-LTSA (\$3,942,510). The non-LTSA work is defined as the work that is not covered under normal planned maintenance in the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items not covered under the LTSA that need to be addressed are labor and material to replace the following: blading, ammonia delivery system, SCR catalyst, turbine rotors, cooling towers, and turbine cooling air cooler.

The following project is less than \$1 million, but is important to reliability:

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- Covert Base Outage Capital (\$391,667). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages.

Q. What is the basis for the projected \$20.274 million capital investment in the projected test period?

A. The projected \$20.274 million capital investment in the projected test period will fund three projects. Two of these projects are greater than \$1 million, and are presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 10, lines 1 and 2. The basis for these projects is described below:

- Covert Plant LTSA (\$13,848,216). This is the capital portion for Mitsubishi negotiated services that cover the planned normal maintenance of each generating unit. The CTGs are a Mitsubishi model M501G1-Kai, the HRSGs are a Deltak model, and the STGs are Mitsubishi. The projected capital expenditures are based upon variable fees paid to Mitsubishi for maintenance services which are based on an EFH basis pursuant to the LTSA. Unlike the GE LTSAs for the Jackson and Zeeland plants, there are no milestone payments associated with the fee structure for the Mitsubishi LTSA. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected pre-mature failures of the equipment. This will help maximize availability and, as a result, optimize customer value for the site. Normal maintenance will ensure the Company continues reliable operation of the units; and
- Covert Plant non-LTSA (\$5,509,565). The non-LTSA work is defined as the work that is not covered under normal planned maintenance in the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items not covered under the LTSA that need to be addressed are labor and material to replace the following: blading, ammonia delivery system, SCR catalyst, turbine rotors, cooling towers, and turbine cooling air cooler.

The following project is less than \$1 million, but is important to reliability:

- Covert Base Outage Capital (\$916,667). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages.

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Karn Units 1 and 2

Q. Please explain the Company's projected capital investment for the 14-month projected bridge period ending February 29, 2024 and the projected test year ending February 28, 2025 for Karn Units 1 and 2.

A. The Company does not plan to make any capital investments on Karn Units 1 and 2 in the 14-month projected bridge period ending February 29, 2024 or the projected test period ending February 28, 2025, as shown on Exhibit A-12 (RTB-3), Schedule B-5.1, page 2, line 15, columns (h) and (j), respectively, due to their retirement on May 31, 2023.

Karn Units 3 and 4

Q. Please explain the Company's projected capital investment for the 14-month projected bridge period ending February 29, 2024 and the projected test year ending February 28, 2025, for Karn Units 3 and 4.

A. The Company plans to invest \$12.446 million in the projected bridge period and \$6.542 million in the projected test period, as shown on Exhibit A-12 (RTB-3), Schedule B-5.1, page 2, line 22, columns (h) and (j), respectively.

Q. What is the basis for the projected \$12.446 million capital investment in the 14-month projected bridge period?

A. The projected \$12.446 million capital investment will fund numerous safety, regulatory compliance, reliability, and infrastructure projects at Karn Units 3 and 4. There are four projects which are greater than \$1 million, and these projects are presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, lines 5 through 8. The basis for these projects is described below:

- Karn Unit 3 Cooling Tower Internal Structure Replacement (\$3,971,429). This project spans the 14-month bridge period and the test year, and its basis is

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included in my discussion of the test year capital projects for Karn Units 3 and 4;

- Tank Farm Storage Tank Heating Line Replacement (\$1,253,571). This project is to replace the condensate piping from the tank farm heating boilers to the “A” storage tank in the Karn Tank Farm. Over the years the piping that supplies heat via hot condensate from the two Johnston tank farm boilers to the storage tank guillotine heaters has degraded due to freeze damage, age, and corrosion. Currently, when supplying heat to the “A” storage tank the Company loses between 10,000-15,000 gallons of city water per day in make-up from the leaks in the system. The two heating lines are encased in a 12” O.D. spiral welded pipe and are uninsulated. Due to the piping being enclosed within the larger diameter pipe, maintenance can be very labor intensive as leaks are difficult to identify. Also, being uninsulated, if the system is not drained properly or continuously run throughout the freezing temperature months, freeze damage is inevitable;
- Karn Units 3 and 4 Sync Wire Replacement (\$1,450,000). The scope of this project is the replacement of the existing copper communication cables between the plant and Hampton Substation. The replacement will consist of fiber optic communication cable from Hampton Substation to the plant and the replacement of Karn Units 3 and 4 generating unit line protection relays, pilot wire differential line protection relaying, telemetry, and control communication at Hampton Substation. Telemetry and control include but are not limited to: breaker position indication, breaker control, transfer trip, bus voltage, and current indication. The Karn Units 3 and 4 auto-synchronizing relay is obsolete. This project will provide a modern reliable communication medium between Karn Units 3 and 4 and Hampton Substation, where the generator synchronization breakers reside. This medium will allow for a reliable means of communication between Karn Units 3 and 4 and the Hampton Substation, thereby reducing the risk of possible failure of the units to synchronize correctly or to trip the units offline for a fault event; potentially causing damage to the generator and turbine, resulting in decreased plant reliability and increased expense; and
- Karn Site Decommissioning (\$1,789,545). The scope of this project includes engineering, procurement and construction activities supporting the separation of various utilities/systems in order to isolate Karn Units 3 and 4 from Karn Units 1 and 2 prior to their retirement in May 2023. The capital expenditures are necessary to comply with the Company’s approved 2018 and 2021 IRPs. The major scope items included in the projected capital expenditure amounts for construction include PJFF air compressor, deionized water trailers, high pressure (High Pressure)\Low pressure (LP) House Water Service & Firewater Systems, DCS systems modifications, intake channel freeze protection, sump discharge line rerouting, and switchyard work.

The following projects are less than \$1 million, but are important to reliability:

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- 1 • Karn Units 3 and 4 Ductwork Expansion Joint Replacement – Induction Draft

2 (“ID”) Fans to Stack (\$950,000). This project spans the 14-month bridge period

3 and the test year, and its basis is included in my discussion of the test year

4 capital projects for Karn Units 3 and 4. This project will replace all expansion

5 joints and entry doors between the ID Fans and the stack. All expansion joints

6 between the ID Fans and the Stack are beyond their end of life and suspected to

7 be severely degraded based upon the condition of expansion joints found during

8 the Karn Unit 3 Breeching project. Failed expansion joints will need to be

9 replaced to maintain environmental compliance. This scope of work will make

10 the ductwork air-tight again to maintain environmental compliance;
- 11 • Karn Unit 4 DCS and Simulator upgrade Evergreen (\$900,000). This project

12 replaces the Karn Unit 4 Ovation DCS with the latest version available at the

13 time of the project. The system is currently running on a VMware virtualized

14 system. The system was installed in 2015 and software upgraded in 2019. This

15 Evergreen will replace the existing Ovation Software, Operating Systems, and

16 miscellaneous upgrades, the controller drops, and rack-mounted servers will be

17 replaced for this upgrade. The DCS must be upgraded at a four-to-five-year

18 upgrade cycle to maintain reliable control and provide recent operating systems

19 and applications that are patchable. Vendor life cycle for DCS versions is

20 generally a five-year cycle. After five years they enter a retired state and are no

21 longer patched. Microsoft Operating Systems are on a limited life basis, and

22 they reach the end of “extended support” and no longer get security patches.

23 Corporate policies require all systems to be patched regularly along with

24 Anti-Virus updates;
- 25 • Karn Unit 3 DCS & Simulator Evergreen (\$540,000). This project replaces the

26 Karn Unit 3 Ovation DCS with the latest version available at the time of the

27 project. The system is currently running on a VMware virtualized system which

28 was installed in 2019. This Evergreen will only replace the existing Ovation

29 Software, Operating Systems, and miscellaneous upgrades. The controller

30 drops and rack-mounted servers will not be replaced for this upgrade. The DCS

31 must be upgraded at a four-to-five-year upgrade cycle to maintain reliable

32 control and provide recent operating systems and applications that are

33 patchable. Vendor life cycle for DCS versions is generally a five-year cycle.

34 After five years they enter a retired state and are no longer patched. Microsoft

35 Operating Systems are on a limited life basis, and they reach the end of

36 “extended support” and no longer get security patches. Corporate policies

37 require all systems to be patched regularly along with Anti-Virus updates;
- 38 • BOP Capital tooling/valves/instrumentation (\$891,667). This project spans the

39 14-month bridge period and the test year, and its basis is included in my

40 discussion of the test year capital projects for Karn Units 3 and 4; and
- 41 • Five additional projects at Karn Units 3 and 4 totaling \$0.700 million which

42 support safety, security, and reliability, with each project representing \$185,000

43 or less in capital expenditures. These projects include replacement of Karn

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Units 3 and 4 Pneumatic Controllers, Karn Units 3 and 4 fire protection replacement, and Karn Units 3 and 4 fleet cyber security, and Primary and Secondary Air Shroud Drives.

Q. What is the basis for the projected \$6.542 million capital investment in the projected test period?

A. The projected \$6.542 million capital investment in the projected test period will fund five projects. One of these projects is greater than \$1 million and is presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 10, line 7. The basis for these projects is described below:

- Karn Unit 3 Cooling Tower Internal Structure Replacement (\$5,000,000). The scope of this project is the replacement of the structural timbers, remaining stacks, and fan blades. The wooden structure is original equipment and has decayed since its installation. The cooling tower provides cooling water for the condenser. The wooden cooling tower structure supports 18 large fans that pull air through the water to drive the evaporation process to cool the water. The wooden structure also supports large water pipes that carry the cooling water to the fill. The water flow to the tower is approximately 240,000 gallons per minute. The entirety of this weight is supported by the wooden structure as it is conveyed to the tower and cascades over the fill. Implementation of this project will provide for reliable operation of Karn Unit 3 through its retirement in 2031.

The following projects are less than \$1 million, but are important to reliability:

- Capital tooling/valves/instrumentation (\$791,667). This project supports capital expenditures for replacement of small valves, instrumentation, tools, equipment, pumps, and motors at Karn Units 3 and 4 during the projected test year;
- Ductwork Expansion Joint Replacement - ID Fans to Stack (\$316,667). This project will replace all expansion joints and entry doors between the ID Fans and the stack. All expansion joints between the ID Fans and the Stack are beyond their end of life and suspected to be severely degraded based upon the condition of expansion joints found during the Karn Unit 3 Breeching project. Failed expansion joints will need to be replaced to maintain environmental compliance. This scope of work will make the ductwork air-tight again to maintain environmental compliance; and
- Two additional projects at Karn Units 3 and 4 totaling \$0.433 million which support safety and reliability, with each project representing \$383,333 or less in capital expenditures. These projects include fleet cyber security and Primary and Secondary Air Shroud Drives.

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Zeeland Plant

Q. Please explain the Company's projected investment for the 14-month projected bridge period ending February 29, 2024 and projected test year ending February 28, 2025 for the Zeeland Plant.

A. The Company plans to invest \$37.879 million in the 14-month projected test period and \$15.286 million in the projected test year at the Zeeland Plant, as shown on Exhibit A-12 (RTB-3), Schedule B-5.1, page 2, line 29, columns (h) and (j), respectively. These capital expenditures will be facilitated, in part, by short outages in the spring and fall of the 14-month projected test period and the projected test year. The Company has an LTSA with GE that covers many reliability issues at the Zeeland Plant.

Q. What is the basis for the projected \$37.879 million capital investment in the 14-month projected bridge period?

A. The projected \$38.879 million capital investment will fund numerous safety, regulatory compliance, reliability, and infrastructure projects at the Zeeland Plant. There are nine projects which are greater than \$1 million, and these projects are presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, lines 12 through 20. The basis for these projects is described below:

- Zeeland Plant LTSA (\$9,520,000). This project spans the projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Zeeland Plant;
- Zeeland - Purchase of Site Spare Generator Step Up ("GSU") Transformer (\$2,883,333). This project spans the projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Zeeland Plant;
- Zeeland Unit 3 Field Rewind of Generator Rotor (\$1,205,357). This project will be executed in the 2023 major outage. There are multiple Technical Information Letters (Bulletins) from the OEM (GE) involving the brazed connections under the retaining rings that need to be addressed as well as

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multiple turn shorts potentially evident by the OEM 2021 health assessments for Zeeland Units 3 and 4. The impacts of turn shorts include: uneven heating of the rotor which will lead to increased seismic vibrations that can create multiple failure scenarios for a field and possible induced rotor bow, higher field current required to match original design which can result in higher heating effects and escalated failure modes, and damage to the retaining rings which will further escalate the vibrational issues. During the major overhaul, the generator rotors will be removed and replaced/rewound, correcting the issue with the connections and shorted turn issue, allowing the units to run to the anticipated end of life;

- Zeeland Unit 4 Field Rewind (\$1,205,357). This project will be executed in the 2023 major outage. There are multiple Technical Information Letters (Bulletins) from the OEM (GE) involving the brazed connections under the retaining rings that need to be addressed as well as multiple turn shorts potentially evident by the OEM 2021 health assessments for Zeeland Units 3 and 4. The impacts of turn shorts include: uneven heating of the rotor which will lead to increased seismic vibrations that can create multiple failure scenarios for a field and possible induced rotor bow, higher field current required to match original design which can result in higher heating effects and escalated failure modes, and damage to the retaining rings which will further escalate the vibrational issues. During the major overhaul, the generator rotors will be removed and replaced/rewound, correcting the issue with the connections and shorted turn issue, allowing the units to run to the anticipated end of life;
- Zeeland Unit 1 GSU Transformer Rewind (\$4,604,082). Zeeland Unit 1 GSU is responsible for stepping up the 215MVA output of Unit 1 generator to the grid from 18KV to 345KV. Since Consumers Energy purchased the site, the Unit 1 GSU Transformer has been producing low levels of Acetylene gas internally. Production of Acetylene is normally an indication of a high energy discharge occurring within the oil space. Acetylene was level and stable at 5 PPM until the combustion turbine 1 52G generator breaker grounding event in 2015 where after re-energization it jumped to 7 PPM and gradually rose to 9 PPM by 2018. However, since 2019, the Acetylene value has increased from around 9 PPM to 23 PPM with a rather noticeable departure from trend rates starting in April 2021. The noted increase as of late is a concerning change from the previous relatively flat line trends and it is usually indication of advanced rates of deterioration than previously observed.

This unit had been operating outside of the recommended Institute of Electrical and Electronics Engineers values of 1-2 PPM historically. Internal inspections were completed in September 2021. The findings by the OEM were significant such that they did not recommend re-energizing the transformer. New GSU procurement is estimated at 24 to 36 months lead time and there was no spare GSU transformer currently known to be available to be used in an emergency. The current unit required a full rewind or other substantial

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dismantling work scope to repair, requiring it to be removed from service and shipped off site for eight or more months. The OEM and company subject matter experts condemned Unit 1.

This project will refurbish the removed GSU Transformer to ensure that the Zeeland Unit 1 generator can safely and reliably supply power to the grid. In addition, this project procured a leased transformer which was used until needed for the continued operation of Zeeland Unit 5;

- Milestone outage capital to GE – part of LTSA contract (\$7,870,000). The milestone payment is made pursuant to the LTSA contract. The milestone payments are required for each gas turbine hot gas path inspection and compensate GE for the new turbine hardware that gets installed during this maintenance evolution;
- Zeeland Plant Combined Cycle 599 and 699 345 kV Breaker Replacement (\$1,222,915). The scope of this project is to replace the 599 and 699 circuit breakers with a type which does not exhibit the failure modes exhibited by the existing design. The existing breakers have a critical design flaw such that an individual pole or poles may not latch open when required. The pole's failure to latch open has the potential to result in lost generation, loss of power to the entire Zeeland substation, and/or generator damage;
- Zeeland Plant HRSG Casing Replacement (\$2,803,333). The HRSG is designed to recover and recycle heat energy from a gas turbine exhaust. A HRSG produces steam that is used to drive a steam turbine. During recent inspections of the HRSGs at the Zeeland Plant, extensive outer casing corrosion has been identified in particular sections of the units. This condition creates the risk of the studs, which hold on the insulation and liner panels, breaking loose and liberating both insulation and liner sheets. The insulation then blows downstream and fouls the HRSG tubes, requiring the unit to be shut down and cleaned, then subsequent casing, insulation, and liner repairs. The affected areas of casing need to be cut out and replaced with new casing; and
- Zeeland Plant LTSA supplementals not included in contract (\$2,900,000). The LTSA supplemental work is defined as the work that is not covered under normal planned maintenance in the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items that need to be addressed are labor and material to replace the following: blading, combustion cans, ignitors, vanes/bushings, and any components on the compressor end as the compressor is not covered under the LTSA.

The following projects are less than \$1 million but are important to regulatory compliance and reliability:

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- Main Steam Non-return Valve Replacement (\$375,000). The scope of this project is to replace both main steam check valves. During inspections in the Fall 2018 outage, cracking was noted on both of the main steam stop-check valve body internals. Cracking is adjacent to a guide rib internal to the valve. With continued plant operation, the cracks are expected to continue to grow, potentially extending through the valve seat, making the valve unable to seal completely. The cracks can also grow to a through-wall crack, resulting in a steam leak. This cracking is a known issue with these types of valves, and is driven by expansion differentials primarily on startup and shutdown. This cracking had initially been noted during a pipe borescope inspection in 2011;
- Replace HP Economizer Level Control Valves (\$461,000). The scope of this project is to replace the HP Economizer Level Control Valves for HRSG 3 and 4. The existing valves are oversized for the operating conditions at Zeeland. This condition results in excessive valve throttling resulting in increased wear on the valves and HRSG quenching during low boiler feedwater feed periods resulting in cyclical thermal shock to tubes. These level control valves were originally designed for steam augmentation of gas turbines – but that feature has never been used and will never be used – consequently, the valve is oversized;
- Zeeland Plant Combined Cycle Steam Turbine Building Roof Replacement (\$600,000). The scope of this project is to replace the turbine building roof and encapsulate the insulation for the combined cycle Zeeland steam turbine. Insulation from the steam turbine building roof is falling from the ceiling, thereby presenting a possible health hazard and also hazard of becoming a foreign material exclusion issue with plant equipment. Replacement of the roof will ensure safe and reliable operation of the steam turbine, and ensure safety of employees by encapsulating insulation;
- Zeeland Plant Base Outage Capital (\$437,972). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages; and
- Fifteen additional projects at the Zeeland Plant totaling \$1.790 million supporting safety, reliability, regulatory compliance, infrastructure, and operations, with each project representing less than \$315,000 or less in expenditures. These projects include Zeeland Units 3 and 4 Air Filter Replacement, Install New 4160V Cross Tie, 299 345kV Breaker Replacement, Unit 5 Transformer Level Gauge Replacement, boiler feedwater pump, and small tools, pumps, motors, valves, and instrumentation.

Q. What is the basis for the projected \$15.286 million capital investment in 2023?

A. The projected \$15.286 million capital investment in the projected test year will fund numerous safety, regulatory compliance, reliability, and infrastructure projects at the

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Zeeland Plant. There are two projects which are greater than \$1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 10, lines 5 and 6. The basis for these projects is described below:

- Zeeland Plant LTSA (\$8,160,000). This is the capital portion for negotiated services that cover the planned normal maintenance of each unit based on its equivalent operating factor fired hours. The planned maintenance includes the following support services (OEM on-site/off-site technical support, engineering, and labor). Typical activities include borescope inspections, capital repairs, unit tuning, addressing service bulletin requirements, and on-site inspections. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected pre-mature failures of the equipment. This will help minimize ROR and it will optimize customer value for the site. Normal maintenance will ensure the Company continues reliable operation of the units; and
- Zeeland Site Spare GSU Transformer (\$3,916,667). The scope of this project is the procurement of a spare GSU transformer for the Zeeland site. The Zeeland Plant consists of four gas turbine powered plants and one steam turbine powered plant. The units transmit their power to the grid via GSU transformers. If a GSU were to fail, then the associated turbine would not be able to transmit power and would not be able to generate energy and capacity market value for Consumers Energy and its customers. For the Zeeland combined cycle plant, the combustion turbine requires the operation of the steam turbine, therefore the loss of the steam turbine's GSU transformer would effectively limit operation of two connected combustion turbine units. The lead time for a GSU transformer is currently 100 weeks and spare units at other facilities typically do not exist. This project would purchase a spare GSU transformer that is sized to be able to replace any of the existing transformers on site and develop redundancy for any minor power upgrades in the future. As previously discussed, the GSU transformer for Zeeland Unit 1 has failed and is being sent out for rewind.

Several other critical projects which are less than \$1 million but are important to reliability and infrastructure include:

- GE DCS Evergreen (\$500,000). The scope of this project is to upgrade the Zeeland Plant Turbine Controls DCS with the latest version available at the time of the project. The system is currently running on a VMware virtualized system which was installed in 2020. This Evergreen will only replace the existing GE Software, Operating Systems, and miscellaneous upgrades. This project will allow the latest versions of control software and operating systems to be used for reliable operation and control of the generating units. The latest feature

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enhancements are also available for operation. This will also allow the latest patches to be applied by the cyber security Emerson Power and Water Cybersecurity Suite (“PWCS”) application. The DCS must be upgraded at a four-to-five-year upgrade cycle to maintain reliable control and recent operating systems and applications that are patchable. The vendor life cycle for DCS versions is generally five years. After five years they enter a retired state and are no longer patched. Microsoft Operating Systems are on a limited life basis, and they reach the end of “extended support” and no longer get security patches;

- Zeeland Plant 299 345kV Breaker Replacement (\$510,075). The scope of this project is to replace the 299 circuit breaker with a type which does not exhibit the failure modes exhibited by the existing design. The existing breaker has a critical design flaw such that an individual pole or poles may not latch open when required. The pole’s failure to latch open has the potential to result in lost generation, loss of power to the entire Zeeland substation, and/or generator damage;
- Site Commons Road Resurfacing (\$475,000). The scope of this project is to perform continued resurfacing of site roads. Several roads require widening to ensure safe 2-way vehicle travel (e.g. road behind substation). Roads/driveways on site require continuous maintenance. The objective of the project is to ensure roadways are safe for both vehicle and pedestrian travel;
- GT Turbine Inlet Filters Replacement (\$325,000). The scope of this project is to replace canister filters. The filters are required to be replaced every five years and must be accomplished during an outage. The purpose of the project is to maintain the integrity of the filters to prevent material ingress to the turbines;
- Zeeland Plant Base Outage Capital (\$413,916). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during unit outages; and
- Twelve additional projects at the Zeeland Plant totaling \$1.002 million support reliability and operations, with each project representing \$250,000 or less in expenditures. These projects include ABB DCS Evergreen, MarkVIe controller replacement, boiler feedwater pump overhaul, filter replacement, and small pumps, motors, valve, instrumentation, tools, and equipment.

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Jackson Plant

Q. Please explain the Company's projected investment for the 14-month bridge period ending February 29, 2024 and test year ending February 28, 2025 for the Jackson Plant.

A. The Company plans to invest \$15.977 million in the 14-month projected bridge period and \$11.720 million in the projected test year at the Jackson Plant, as shown on Exhibit A-12 (RTB-3), Schedule B-5.1, page 2, line 36, columns (h) and (j), respectively. This will be facilitated by short outages in the fall of 2023 and 2024. The Company has a LTSA with GE to cover many reliability issues at the Jackson Plant.

Q. What is the basis for the projected \$15.977 million capital investment in the 14-month projected bridge period?

A. The projected \$15.977 million capital investment in the 14-month projected bridge period will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are three projects which are greater than \$1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, lines 9 through 11. The basis for these projects is described below:

- Jackson Plant LTSA (\$9,570,928). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Jackson Plant;
- CTG 7 Replace Turbine Casing (\$2,088,234). The scope of this project is the replacement of the turbine casing and bolting that holds the two-part casing together. Industry experience has shown that the casing bolting is susceptible to failing, resulting in catastrophic failure. Based on condition assessments of the turbine casing, the Company will conduct this work during the major outage in 2023; and
- Scanners and Igniters Replacement (\$2,020,513). Reliable ignition is critical for the increasing use of on/off cycling and low load operation. As the plant cycles on and off and operates at low load, the duct burners are not used. The HRSG duct burners are utilized when increased MW demand is required. The

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igniters are used to light off the duct burners. The current scanners and igniters are at end of life. This project would also add solenoids to the assemblies so individual rows of ignitors and duct burners can be isolated for repairs while the other duct burners are in service. This cannot be done in the present configuration as there is no isolation at the igniters.

Several other critical projects which are less than \$1 million but are important to reliability and infrastructure include:

- Jackson Plant LTSA Extra Work (\$428,333). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Jackson Plant;
 - LM6000 Beckwith Relay Replacement (\$390,914). The scope of this project seeks to replace the LM6000 Generator Protective Relays with direct replacement relay upgrades and install test facilities in a pre-planned fashion. This will protect the generation assets and avoid issues with the obsolescence of the existing equipment. Jackson Units 1 through 6 are currently protected with Beckwith M3420 Relays. These relays protect the generator from internal and external system fault events and are obsolete. The long lead time replacement M-3425A relays have been purchased, and are awaiting installation.
- In addition to being obsolete, the existing relays have limited, or no means for communication, fault analysis, troubleshooting, and event recording following an electric fault event. The current relays also do not have external test facilities for periodic maintenance. Because of this, the relays need to be un-wired to test, and then rewired. This increases maintenance time, as well as exposes the plant to unplanned operations due to human error;
- Base Outage Capital (\$320,000). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Jackson Plant;
 - Jackson Plant Units 1 – 6 Singular Annular Combustor (“SAC”) Extended Life Combustor (\$189,583). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Jackson Plant; and
 - Nine additional projects at Jackson Plant totaling \$0.968 million, with each individual project representing \$275,833 or less in expenditures. These projects include NO_x Umbilical Replacements, RO pretreatment system, major motor and pump overhauls, and small valves, instrumentation, tools, equipment, pumps, and motors.

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1 **Q. What is the basis for the projected \$11.720 million capital investment in the projected**
2 **test year?**

3 A. The projected \$11.720 million capital investment in the projected test year will fund
4 numerous safety, regulatory compliance, reliability, and infrastructure projects. There are
5 two projects which are greater than \$1 million, and they are presented on Exhibit A-12
6 (RTB-3), Schedule B-5.1, page 10, lines 3 and 4. The basis for these projects is described
7 below:

- 8 • Jackson Plant LTSA (\$8,244,761). This is the capital portion for negotiated
9 services that cover the planned normal maintenance of each unit based on its
10 equivalent operating factor fired hours. The Jackson Plant is comprised of nine
11 generating units. Units 1 through 6 are GE Model LM6000PC Gas CTG each
12 with a HRSG attached to the exhaust of the Combustion Turbine. Unit 7 is a
13 GE Model Frame 7EA CTG with a HRSG, and Units 8 and 9 are GE STGs
14 powered by the steam created from the 7 HRSGs. The planned maintenance
15 includes the following support services: OEM on-site/off-site technical support,
16 engineering, and labor. Typical activities include borescope inspections, capital
17 repairs, unit tuning, address service bulletin requirements, and on-site
18 inspections. Based on the OEM's operating and historical experience, if the
19 Company executes the normal planned maintenance and inspections according
20 to the recommended schedules, the Company will mitigate unexpected
21 pre-mature failures of the equipment. This will help maximize availability and,
22 as a result, optimize customer value for the site. Normal maintenance will
23 ensure the Company continues reliable operation of the units; and
- 24 • Jackson Plant Units 1 – 6 SAC Extended Life Combustor (\$1,338,458). The
25 scope of this project is to remove the G42 combustor and replace it with the
26 new Rich Quench Mixture ("RQM") combustor during hot gas path
27 inspections. Specifically, this project will perform an operational study to
28 operate a RQM combustor in a steam/gas configuration and attempt to achieve
29 15 ppm NO_x. The study will be to install an RQM combustor on 1 of the 6
30 LM6000s. If the operational study proves to be successful, an RQM combustor
31 would then be installed on all LM6000 units. There are 7 total, 6 in service and
32 1 spare.

33 The Jackson Plant's LM6000 units currently utilize a G42 Jet-Rad
34 combustor. In recent years, the OEM developed the Rad-Rad (G48) design
35 combustor to increase the longevity of primary and secondary swirlers by
36 improving the materials to prevent or reduce their cracking over time and
37 reduces thermal barrier coating loss on high pressure turbine stage 1 blades.
38 More recently, the RQM combustor has been introduced by GE. The RQM

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combustor liners improve dilution characteristics by repositioning combustion location and lowering combustion area for lower emissions. The RQM combustor is expected to significantly increase the combustor section life (32,500 hours vs. 25,000 hours). Upgrading the combustor section of each LM6000 to a RQM combustor also has the potential of lowering the NO_x production for each unit, which would result in more full load capability. The LM6000 units currently operate with emissions of 25 PPM NO_x and 40 PPM CO. The 12-month rolling NO_x limit is 95 tons per year, per engine. The 12-month rolling CO limit is 360 tons per year for the site for the six LM6000 units. The 12-month rolling NO_x limit is the limiting factor for the site in regard to running the units near full load capability for the entire year; at times the engines have to be curtailed due to NO_x emission limits.

Several other critical projects which are less than \$1 million but are important to reliability and infrastructure include:

- Jackson Plant LTSA Supplemental Work (\$600,000). The LTSA supplemental work is defined as the work that is not covered under normal planned maintenance in the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items that need to be addressed are labor and material to replace the following: blading, combustion cans, ignitors, vanes/bushings, and any components on the compressor end as the compressor is not covered under the LTSA;
- Base Outage Capital (\$300,000). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages; and
- Thirteen additional projects at Jackson Plant totaling \$1.237 million, with each individual project representing \$225,000 or less in expenditures. These projects include NO_x Umbilical Replacements, Combustion Turbine Inlet Canister Filter Replacement, 480V Breaker (WavePro) Overhaul, major motor and pump overhauls, and small valves, instrumentation, tools, equipment, pumps, and motors.

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HYDRO UNITS

Q. Please explain the Company's projected capital expenditures for the 14-month projected bridge period ending February 29, 2024 and the projected test year ending February 28, 2025 for the Hydro Units.

A. The Company plans to invest \$36.662 million in the 14-month bridge period and \$48.897 million in the projected test year in the Hydro Units, as shown on Exhibit A-12 (RTB-3), Schedule B-5.1, page 3, line 64, columns (h) and (j), respectively.

Q. What is the basis for the projected \$36.662 million capital investment in the 14-month projected bridge period?

A. The projected \$36.662 million capital investment will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are twelve projects which are greater than \$1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, lines 21 through 32. The basis for these projects is described in the direct testimony of Company witness Monroe.

Q. What is the basis for the projected \$48.897 million capital investment in the projected test year?

A. The projected \$48.897 million capital investment in the projected test year will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are 13 projects which are greater than \$1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 10, lines 8 through 20. The basis for these projects is described in the direct testimony of Company witness Monroe.

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LPS

Q. Please explain the Company's projected capital expenditures for the 14-month projected bridge period ending February 29, 2024 and the projected test year ending February 28, 2025 for the LPS.

A. The Company plans to invest \$13.623 million in the 14-month projected bridge period and \$14.137 million in the projected test year in the LPS, as shown on Exhibit A-12 (RTB-3), Schedule B-5.1, page 3, line 71, columns (h) and (j), respectively. These capital investments will be periodic outages in the spring of 2023 and 2024.

Q. What is the basis for the projected \$13.623 million capital investment in the 14-month projected bridge period?

A. The projected \$13.623 million capital investment in the 14-month projected bridge period will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are five projects which are greater than \$1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, lines 33 through 37. The basis for those projects is described below:

- LPS Oil Water Separator Replacement (\$1,162,917). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;
- Powerhouse Roof Wearing Surface and Weather Proofing Replacement (\$2,724,054). The scope of this project includes engineering of the demolition, disposal, and replacement of the concrete wearing surface and waterproofing. This project began in 2018 with actual capital expenditure amounts of \$0.036, \$0.074, \$0.095, and \$0.230 million for 2018 through 2021, respectively. The 2022 capital expenditure of \$2.325 million covered material procurement and installation. This project was delayed due to the project extension for the Ludington Unit 3 upgrade. The LPS powerhouse roof wearing surface and waterproofing has deteriorated and needs to be replaced. The powerhouse roof has only had minor repairs since the plant was originally constructed. Currently, there is water seeping through the roof and leaking onto electrical

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equipment. Failure to remedy this situation exposes the electrical equipment to water intrusion and premature failure;

- DCS Control Relay Replacement (\$1,347,516). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;
- Replace Lower Penstock Expansion Joint (“LPEJ”) Chamber Waterstop (\$2,425,493). The scope of this project is replacement of the LPEJ waterstop and potentially dewatering the surrounding groundwater. The engineering study was performed in 2020 at a cost of \$0.404 million and project implementation began in 2021 and is expected to be completed in 2023.

In 2021, the engineering was completed, and the design was approved by FERC. In addition, the Unit 3 chamber was stabilized to allow for the Unit 3 waterstop to be replaced without impacting the penstock or impacting the long-term ability to generate from Unit 3. The Unit 3 chamber was stabilized due to the 1.3" of offset due to settlement of the upstream side of the chamber; this impacted the steel expansion joint portion of the penstock. To mitigate the risk of the penstock binding and ensure continued operability of Unit 3, the Unit 3 chamber was stabilized by installing a secant pile shaft and placing grout underneath the chamber to raise it back to its pre-2017 state.

The LPEJ Chambers enclose the penstock expansion joints in concrete chambers. The penstock expansion joints allow penstock expansion with seasonal temperature changes. The waterstop is a membrane intended to prevent groundwater from leaking into the LPEJ. Some joints have been leaking since shortly following plant construction. In February 2017, a depression was discovered upstream of Ludington Unit 3, which was caused by transport of soil into the chamber by inflowing groundwater. Historically, Consumers Energy sealed the leaks into the LPEJs using hydrophobic polyurethane grout. However, the waterstops are at the end of their expected life and grouting is no longer an effective solution. Failure to remedy the in leakage is a threat to generation because if the settlement of the chambers reaches a certain threshold, the generation unit(s) will remain in a forced outage until the LPEJ chamber(s) can be stabilized. The implementation of this project reduces current risk of a potential failure mode and supports Ludington unit generation well into the relicensing period; and

- Replace Barrier Net Panels (\$1,088,614). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington.

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The following projects are less than \$1 million but are important to regulatory compliance and reliability:

- Replacement of LPS Depression Air Compressors (“DAC”) 1 and 2 (\$565,750). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;
- Replace 480V DLCs (\$990,030). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;
- Admin Building Addition (\$592,377). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;
- LPS Intake Gate and Gate House Mechanical Replacement (\$476,287). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;
- Governor Replacement (\$345,000). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;
- 19-420 Station Battery Replacement (\$265,833). The scope of this project is to replace battery banks 1 and 2. This project will include the installation of new racks and a new battery monitoring system. Ludington relies on two (North American Electric Reliability Corporation (“NERC”) compliance) battery banks (1680 amp hours each). Station battery bank 1 provides power to critical control and protection systems for Units 1,2, and 3, while Station battery bank 2 provides power to critical control and protection systems for Units 4, 5, and 6. The banks also provide power to the emergency diesel generator during a black start event. These systems were installed in 2009 and have reached the end of life. The system also is due for a load study to verify its capabilities now that major modifications have been made to systems dependent on the batteries. Failure to maintain battery capacity could risk plant control, and the ability to black start;
- Design and Install Barrier Net - pursuant to the Adaptive Management Process (\$358,790). This project is a multi-year project which is being implemented in accordance with the Ludington Relicensing Settlement Agreement, Appendix B (between Consumers Energy, DTE, and various state, federal, and tribal agencies), and the FERC project license for Ludington. This project began in 2020 at a cost of \$0.166 million in 2020 and \$0.610 million in 2021. This project is projected to continue through 2025, requiring studies and improvements pursuant to the agreement. The objectives of this project are to

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optimize barrier net operations and maintenance functions to reduce fish entrainment mortality during pumping and generation, consistent with safety considerations; optimize barrier net design and placement to improve barrier net performance, utilize data from fish community characterization studies to help inform and optimize barrier net design and operations; utilize the results of technology reviews to improve barrier net performance through potential changes in design or deployment; and the implementation of fish entrainment prevention technologies;

- LPS - Draft Tube Water Level Sensing System Replacement (\$357,000). Each unit at the LPS has a water column located on D-floor east, elevation 535'. The water column is used to detect water level when the unit is depressing water out of the runner area during pump start or during synchronous condense mode. The entire system is composed of a tubular column, valves and strainers, 4 level electrodes, a sight glass, feedback relays, and a transformer. All the components mentioned above are original to the plant's construction and have been operating for 50 years. Over the course of the plant's operation these components have gradually worn and corroded. Since these components are in a submerged water application with high oxygen content corrosion occurs more quickly. The metallic materials are now at the end of their useable service life. Due to the criticality of the system, there is a risk of over pressurizing the draft tube/depressing the entire draft tube. If this were to occur, damage to the turbine could occur; and
- Twenty-four additional projects at LPS totaling \$0.923 million, with each individual project representing \$193,958 or less in expenditures. These projects include Intake Battery Bank, Battery Charger and UPS Replacement, Centralized Grease System Replacement, CO² fire protection system replacement, and small tools, pumps, motors, valves, and instrumentation.

Q. What is the basis for the projected \$14.137 million capital investment in the projected test year?

A. The projected \$14.137 million capital investment in the projected test year will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are four projects which are greater than \$1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 10, lines 21 through 24. The basis for these projects is described below:

- DCS Control Relay Replacement (\$2,500,656). The scope of this project is to replace and eliminate worn and less reliable control relays with new electronic input/output modules and new relays where needed. The number of hardware

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control relays will be reduced due to the "control" being performed in logic instead of "hardwired" circuits. This will increase reliability and reduce outages and unit derates. Common control and monitoring of system equipment allows operation of the equipment from the Human Machine Interface ("HMI") graphics and keeps the operator focused on one system instead of monitoring several systems from several areas of the control room.

The LPS units are controlled by using the original hardwired electromechanical relay control system to operate the units. This 1970's technology does not provide the diagnostic and troubleshooting capabilities of a modern DCS. Any updates of equipment and systems that are integrated with the unit operation are difficult to automate with the original relay logic, and changes to operating criteria are difficult to implement, test, and verify and are more costly and time-consuming when compared to the capabilities of a modern DCS.

The existing relay control system is based on electromechanical devices that wear and become less reliable over time. The relay contacts wear, and increased resistance can cause intermittent failures. This may cause units to be unavailable or derated. Troubleshooting these issues are difficult and time-consuming. The relay control system will not last until end of life of the units and need to be upgraded to a modern DCS control system. The Emerson Ovation DCS infrastructure was installed as part of the 2019-2021 Data Acquisition System ("DAS"), Annunciator, Programmable Logic Controller ("PLC"), and Sequence of Events recorder replacement project. This provides a common historian, HMI graphics control, alarm management system and modern control system for reliable efficient unit operation. The DAS project provides the infrastructure to build upon for full site/unit control at LPS;

- Replace Barrier Net Panels (\$1,752,840). The panels are a regulatory required system to minimize fish entrainment. The panel replacements are primarily time based. Ludington has extensive operating experience with these panels, which helps determine when a replacement is required. Similar funding amounts are included for both the projected bridge period and test year;
- Intake Gate and Gate House Mechanical Replacement (\$1,118,228). The LPS intake gates and associated hoist equipment are the primary form of mechanical protection for the LPS units. Their purpose is to isolate the stored energy from the reservoir's water against each unit's penstock when dewatering or during emergency conditions such as a penstock rupture or governor failure. Reliable operation of this system is critical to minimize damages from a unit run away condition or a penstock failure, acting as a last effort to control unit overspeed. The mechanical system of the intake gate hoist is all original (circa 1971) and recent OEM inspection revealed that its condition is poor and in need of refurbishment. Updates and repairs are required to support the current facility license extension of 2069. The electrical control system is well past its design

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service life. This outdated technology is obsolete, and certain critical components are no longer available for spare parts. Modern technology offers more reliable options that would give the system an additional 30 years of service. The head gate hoist is enclosed in a steel structure on top of the intake (head gate enclosure). The head gate hoist enclosures are original to the plant and have rusted out in many places. Significant corrosion has been noted on the steel frame, the connections, and the beams. These enclosures need to be replaced as they are beyond a repair option; and

- Administration Building Addition (\$2,713,585). The scope of this project is to construct a permanent office space for the employees of the Ludington Plant. Currently, many offices at the Ludington Plant are housed in a temporary construction office building. The construction trailers need to be demolished and a permanent office needs to replace them. The temporary office was only intended for use until 2020. The construction of a permanent building addition minimizes the potential for slip trip and falls because employees will no longer need to go outside to travel between the offices in the construction trailers and the Administration Building in the winter.

The following projects are less than \$1 million but are important to regulatory compliance and reliability:

- LPS Oil Water Separator (“OWS”) Replacement (\$577,083). The scope of work for this project is to install a separate, parallel train OWS to that of the plant’s existing OWS, modify existing support systems (station sump, station sump pumps, & metering devices) to support new OWS, and retrofit the existing OWS to improve oil separability. This will allow temporary use of the modified original OWS while servicing the anticipated new one as to not impact unit availability. The project is being performed in order to comply with requirements for effluent discharge during all modes of operation and process upset conditions. The failure to perform this project would likely lead to additional releases in excess of the National Pollutant Discharge Elimination System permit requirements throughout the facility’s lifecycle. Although not quantified, cost for these releases could be significant in terms of potential fines, reputational damage, cleanup costs, and other intangibles;
- LPS All Unit Critical Valve & Actuator Replacement (\$413,833). The scope of this project is to replace valves, actuators, and associated equipment critical to unit specific operation. There are also certain valves that provide routine tagging points that provide worker protection. Many of these valves have known issues such as damaged seals (leakage when the valve is closed), leaking packing (cannot be tightened further), and severely corroded valve stem extensions. Additionally, many of these valves are paired with pneumatic actuators which have also been identified with operational issues. Most of the handwheels are broken and do not provide a secondary means of operating the valve if the pneumatic actuator were to fail. This could present a particularly

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dangerous situation if a pipe were to fail. Additionally, damage to the actuator linkages and slides have been noted in previous inspections. The linkage damage has introduced play or slop into the mechanism which can be seen during operation and will lead to eventual failure of the mechanism;

- Governor Replacement (\$424,167). The scope of this project is to contract with a specialized vendor to inspect, repair as required, and modernize the unit governors. The LPS unit governors have not been overhauled in approximately 15 years and, as a result, regularly show signs of wear during routine maintenance;
- Centralized Grease System Replacement (\$454,249). The scope of this project is to replace end of service life components such as pumps, distributing blocks, and solenoid valves, and to modernize the control system to a self-diagnostic PLC system. The current electro-pneumatic grease system(s) that service the wicket gate bushings are functionally past their service life and of questionable reliability (original plant equipment);
- Breakwater Tetrapod Project (\$682,433). The scope of this project is to install concrete tetrapods on the entire west face of the breakwater. The system will need to be engineered to determine the exact size of the tetrapods to prevent ice from dislodging tetrapods and protect the tailrace from Lake Michigan. The engineering for this project will be done in 2024 with fabrication and installation to be done in 2026.

The breakwater in the tailrace of the Ludington Plant goes across the west end of the tailrace. The breakwater is made of large rip rap and core stone underneath it. The breakwater protects the plant from Lake Michigan. Over the years, the rip rap has been displaced and dragged out of the breakwater by ice. There are some sections where there is no longer rip rap above water. New shoreline protection needs to be placed to protect the powerhouse from Lake Michigan. The Company repaired as much as possible for \$300k in 2019. However, additional funding is necessary to restore the breakwater to its designed dimensions. To address this, concrete tetrapods will be installed on the entire west side of the breakwater as an improvement to protect the plant. The tetrapods interlock together, preventing ice from dragging it out into Lake Michigan. The large concrete tetrapods are designed to endure large wave action and protect the powerhouse from large waves from Lake Michigan;

- 20 kW Main Transformer Bank (“MTB”) Disconnect Replacement (\$350,375). This project will install safe and reliable disconnect switches designed for electrical isolation. Currently, the station relies on the removal of physical links and numerous administrative controls to obtain working clearance that could create a hazard if not strictly adhered to. Installation of disconnects with grounding ability would mitigate the potential safety hazards to personnel and eliminate contamination of the ISO Phase Bus. These disconnects will significantly reduce the required administrative controls and exposure to

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conductors, thus reducing the probability of a safety hazard from human performance or engineering deficits. This would also provide LPS a safe, reliable means of separating units (including the Power Potential Transformer (“PPT”)) from the MTB, eliminating the need for and additional PPT disconnect project. Providing quicker means to disconnect and reconnect the units from their MTB, without impacting the adjacent unit, would mitigate almost all negative cash flows realized to isolate a unit from its MTB for the remainder of the site’s life. Installing “no load” disconnect and safety ground switches in strategic locations would mitigate almost all O&M labor dollars associated with manual efforts at the links, as well as mitigate the loss of revenue incurred on the non-outage unit affected for the amount of time required to execute these evolutions. This effort will install new equipment, improving safety when isolating the 20 kV system for the remainder of site life;

- Replace 480V DLCs (\$851,900). The scope of this project is the replacement of the 20 480V DLCs over a six-year period that began in 2020 at a capital expenditure amount of \$0.671 million. The DLCs are original plant equipment and suffer from corrosion and deterioration. The primary purpose of the DLCs is to distribute power to 193 dike drain pumps and 34 pumping relief wells located around the reservoir. The purpose of the dike drain pumps is to keep the upstream face of the dike in a drained condition and to protect the asphalt liner from damage due to differential pressure. The purpose of the pumping relief wells is to keep groundwater at pre-construction levels, thereby minimizing the likelihood of a downstream slope failure. Replacement of the DLCs over a six-year period will provide high electrical system reliability and ensure FERC compliance;
- Replace Barrier Net Panels (\$374,102). The panels are a regulatory required system to minimize fish entrapment. The panel replacements are primarily time based. LPS has extensive operating experience with these panels, which helps determine when a replacement is required. Similar funding amounts are included for both 2022 and 2023; and
- Twenty-four additional projects at Ludington totaling \$1.923 million, with each individual project representing \$239,317 or less in capital expenditures. These projects include pony motor isolation switch life cycle project, station power transformer life cycle management, replacement of LPS DAC 1 & 2, and small tools, pumps, motors, valves, and instrumentation.

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ADMINISTRATIVE AND OTHER

Q. Please explain the Company's projected capital expenditures for the 14-month projected bridge period ending February 29, 2024 and the projected test year ending February 28, 2025 for Administrative and Other.

A. The Company plans to invest \$1.252 million in the 14-month projected bridge period and \$0.979 million in the projected test year in Administrative and Other, as shown on Exhibit A-12 (RTB-3), Schedule B-5.1, page 3, line 78, columns (h) and (j), respectively.

Q. What is the basis for the projected \$1.252 million capital investment in the 14-month projected bridge period for Administrative and Other?

A. The projected \$1.252 million capital investment will support several projects during 2022.

The basis for these projects is described below:

- Enterprise Project Management Office Transformation—Enterprise Project Management Information System (\$437,187). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Administrative and Other;
- Generation Operations – Ovation security center replacement evergreen (\$300,000). The Generation control systems cyber security tool that is used for control system security is PWCS. This tool is comprised of multiple cyber security products used in the industry today. Because of the quickly changing technology and techniques used by hackers, the cyber security tools require an increased update cycle of two to three years. The Karn site has been using the PWCS tool for 10 years. It was last upgraded in 2017. To support the latest version of Ovation DCS, the PWCS system must be upgraded. This replacement will support the protection of multiple components of the control system across multiple sites including Karn Units 3 and 4, Campbell, Jackson, Zeeland, and Ludington. The tools included are:
 - Anti-Virus
 - Malware Prevention with Application Control
 - Patch Management
 - Device Control
 - Rogue System Detection
 - System Backup and Recovery

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- Security Incident and Event Manager
- Change Management; and

- Laptop and capital business tool purchases for Generation Engineering, Electric Supply, Environmental Services, Lab Services, Business Services, and Enterprise Project Management (\$515,000).

Q. What is the basis for the projected \$0.979 million capital investment in the projected test year?

A. The projected \$0.979 million capital investment in the projected test year will fund several projects. The basis for these projects is described below:

- Laptop and capital business tool purchases for Generation Engineering, Electric Supply, Environmental Services, Lab Services, Business Services, and Enterprise Project Management (\$645,000); and
- Enterprise Project Management Office Transformation—Enterprise Project Management Information System (\$333,963). The scope of this project is to provide for the continuing upgrade of the Company’s project management tools and methods, allowing better tracking and more effective project implementation. The additional capital will continue to support continuing enhancements of the project management information system (“PMIS”) which was chosen by the Company after proof of concept on the Ludington overhaul project as well as a request for proposal process which evaluated eight comparable products. The benefits of implementing the PMIS (Primavera Unifier (“Unifier”)) include resolution of an external audit finding, increased project management efficiency, and speed of delivery. Unifier provides the tools, technologies, and processes for project management to control the risks associated with delivering a large portfolio of capital projects valued well into the billions of dollars. The project spending will include configuration management as well as quarterly Unifier enhancements based upon ongoing feedback and recommendations from the users of Unifier. The projected capital expenditures in both the 14-month bridge period and the test year represent the electric share of the total projected capital expenditures.

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COMPANY-OWNED SOLAR RESOURCES

Q. Please explain the Company's projected capital expenditures for the 14-month projected bridge period ending February 29, 2024 and the projected test year ending February 28, 2025 for Company-owned solar resources.

A. The Company plans to invest \$417.180 million in the 14-month projected bridge period and \$269.457 million in the projected test year in Company-owned solar resources, as shown on Exhibit A-12 (RTB-3), Schedule B-5.1, page 2, line 50, columns (h) and (j), respectively.

Q. What is the basis for the projected \$417.180 million capital investment in the 14-month projected bridge period?

A. The projected \$417.180 million capital investment in the 14-month projected bridge period will fund the IRP-approved solar generation development. This entire investment amount is reflected in three separate projects, Mustang Mile, Washtenaw, and Muskegon Solar, which are each greater than \$1 million and are presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, lines 38 through 40. The basis for these projects is described in the direct testimony of Company witness Clark.

Q. What is the basis for the projected \$269.457 million capital investment in the projected test year?

A. The projected \$269.457 million capital investment in the projected test year will fund the IRP-approved solar generation development. This entire investment amount is reflected in three separate projects, Mustang Mile, Washtenaw, and Muskegon Solar, which are each greater than \$1 million and are presented on Exhibit A-12 (RTB-3), Schedule B-5.1,

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1 page 10, lines 25 through 27. The basis for those projects is described in the direct
2 testimony of Company witness Clark.

3 **Q. Are you supporting any other projected capital expenditures for generation related**
4 **projects in the test year ending February 28, 2025?**

5 A. Yes. I am also supporting an Information Technology ("IT") project, Generation
6 Operations Digital Work Management. The test year projected capital expenditure amount
7 is \$1.379 million, and the test year projected O&M expense amount is \$0.110 million.
8 These amounts are reflected in the exhibits of Company witness Heather M. Weller. The
9 scope of this project is to provide durable mobile devices, software, and digital forms for
10 Electric Generation at LPS, wind parks, and hydro facilities.

11 **Q. What are the benefits of this technology project?**

12 A. This project will provide faster retrieval and updates of procedures, equipment statistics,
13 work order data, and time entry. The current work management process for Electric
14 Generation at the wind parks, hydro facilities, and LPS is cumbersome and largely paper
15 based outside of desktop kiosks; resulting in process waste, re-work, and human error. This
16 project provides benefits through: (1) increased productivity by reducing the need to return
17 to the desktop kiosk for updates; (2) improved quality through increased accuracy of
18 updates completed at the time and place of the work; and (3) improved safety through
19 real-time information used at work sites rather than printed procedures or drawings.

20 **Q. What is the specific scope of the project?**

21 A. The specific scope of the project includes the initial roll out for Electric Generation at LPS,
22 wind parks, and hydro facilities, which would include mobile devices, software, and
23 enhanced wireless connection.

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1 **Q. Did the Company consider alternatives for this project?**

2 A. Yes. The alternatives considered include: (1) Utilize an SAP work management mobile
3 solution. An SAP work management solution is not preferred since it is a new solution and
4 requires additional project and support cost; (2) Continue the manual paper-based process.
5 Continuing the manual paper-based process was not chosen because of process waste,
6 re-work, and human error; (3) Customize the existing electronic Shift Operations
7 Management System (“eSOMS”) mobile application to add work management functions.
8 A custom eSOMS mobile application was not chosen because it would require additional
9 project cost and an ongoing support budget for a custom solution that the eSOMS product
10 was not intended to support; (4) Utilize the existing Service Suite solution currently
11 deployed for Gas and Electric Distribution in combination with digital forms. The
12 combined Service Suite and digital form solution is the preferred option because it is a
13 proven solution at the Company and provides the mobility and digital benefits at a lower
14 cost.

15 **GENERATION CAPITAL EXPENDITURES—SUMMARY**

16 **Q. Are the Company’s capital expenditures in power generation reasonable and**
17 **prudent?**

18 A. Yes. As discussed, the proposed capital expenditures are directly aligned with the
19 Company’s generation asset strategy and, as a result, will provide economic value for
20 power supply customers in the energy and resource adequacy markets. Other capital
21 expenditures in generation are related to regulatory and environmental compliance, and
22 thus are not discretionary. Company witnesses Clark and Monroe provide additional
23 discussion in their direct testimony.

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SECTION IV

GENERATION O&M EXPENSE

Q. What are the major drivers in determining the O&M expense levels you are sponsoring in this proceeding?

A. The major drivers are identifying the funding needed to support the daily operation and maintenance of the Company's fleet of generating facilities and identifying the funding needed for certain internal organizations that support Generation Operations.

Q. For purposes of your direct testimony in this case, what does the Generation O&M cost represent?

A. In addition to the Company's generation fleet, I am sponsoring the O&M expenses for the Electric Supply Operations and PSCR organization, Electric Regulation and Strategy Implementation organization, Financial Planning organization, Renewable Energy Department, Contracts and Settlements organization, Generation Asset Management organization, Electric Sourcing and Resource Planning organization, and Enterprise Project Management and Environmental Services organization.

Q. Please describe Exhibit A-41 (RTB-4), page 1, Generation Operation and Maintenance Expenses.

A. Exhibit A-41 (RTB-4), page 1, identifies the actual 2022 through 12 Months Ending February 28, 2025 projected Generation O&M expenses. Specifically:

- Column (a) identifies each O&M expense category;
- Column (b) identifies the Actual 2022 Generation O&M expense as \$150,030,678;
- Column (c) identifies the 14-Month Projected Bridge Period Generation O&M expense as \$172,465,337; and

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- Column (d) identifies the Projected Test Year Generation O&M expense as \$164,251,928.

HISTORICAL O&M EXPENSE

Q. How does Consumers Energy determine the level of Generation O&M spending?

A. Consumers Energy tracks the history and projects future maintenance needs of each unit. Personnel at the plants provide information on maintenance for each site or specific units. Once costs to operate and comply with regulations are prioritized, the Asset Strategy and Generation Planning organizations evaluate the plans required to maintain and/or improve the condition of the plant – weighing the estimated benefit to the customer for each project. Using this combination of information, a preliminary plan is prepared and reviewed to ensure high-priority issues are addressed and adequate resources and funding are available. After all appropriate levels of management have reviewed and approved the maintenance plan, a schedule is created. The overall objective is the safe, reliable, cost-effective generation of electricity.

Q. How are Generation O&M expenses categorized?

A. Generation O&M expenses are categorized into four primary components – “Base,” “Environmental Operations,” “Major Maintenance,” and “Retention and Separation.”

Q. What are Base O&M expenses?

A. Base O&M expenses are comprised of two categories – labor and non-labor. Labor is the primary component and typically has a predictable, stable rate of increase. Because most of the Company’s generating units have been in service for years, the Company has an excellent basis upon which to make accurate forecasts. Non-labor expenses also tend to increase at a predictable rate and include items required to operate the plants. These items include but are not limited to: (1) fuel (diesel and gasoline) for equipment and vehicles;

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(2) material; (3) tools; (4) cleaning supplies; (5) facilities; (6) security; and (7) road and grounds maintenance.

Q. Please explain how the 2022 Actual O&M expenses were developed.

A. The 2022 Actual O&M expenses were taken from Consumers Energy's internal accounting records.

Q. Please explain how the 14-month projected bridge period and projected test year Base O&M expenses were determined.

A. Base O&M expenses for the projected bridge period ending February 29, 2024, and projected test year ending February 28, 2025 shown on Exhibit A-41 (RTB-4), page 1, line 1, columns (c) and (d), were determined by considering staffing levels and historical spending. Total O&M expense for the years 2022 through the projected test year demonstrates average annual increases of 4.3%. As discussed later in this direct testimony, this average annual increase includes an adjustment related to the retirement of Campbell Units 1, 2, and 3 on May 31, 2025. Exhibit A-41 (RTB-4), page 1, lines 3 and 4, identify Adjusted O&M expenses which are new or projected to change from past years' expense levels. These include items that are required by law to maintain environmental compliance, for the safety of employees, and to support the reliability of service to customers, specifically, Environmental Operations and Major Maintenance. Exhibit A-41 (RTB-4), page 1, line 5, identifies Adjusted O&M expenses which are related to Retention and Separation expenses associated with the Karn and Campbell site. These expenses are required for safe and reliable operation of Karn Units 1 and 2 through May 2023 retirement and Campbell Units 1, 2, and 3 through May 2025 retirement.

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1 **Q. Please explain Exhibit A-41 (RTB-4), page 2.**

2 A. Exhibit A-41 (RTB-4), page 2, presents the amounts of the projected O&M expenses that
3 were developed by applying either an inflation rate or contract rate to historical O&M
4 expense. Column (b) presents the historical O&M expense. Column (c) presents the
5 amount of the historical O&M amount to which an inflation rate or contract rate applies.
6 Columns (e) and (g) present the amounts to which an inflation rate or contract rate were
7 applied for each period, respectively. Columns (d), (f), and (h) present contract and
8 inflation increases for each respective period. Amounts that were projected using other
9 methods are included in column (i). Column (j) is the projected test year O&M and is the
10 sum of columns (b), (d), (f), (h), and (i).

11 **Q. Please explain how the various inflation and contract rates were applied to Labor,**
12 **Material, Contractor, and Non-Labor Other O&M expense on Exhibit A-41 (RTB-4),**
13 **page 2.**

14 A. The historical labor on line 1, column (b) reflects a combination of both Operating
15 Maintenance and Construction ("OM&C") and non-represented labor. Inflation rates of
16 3.9%, 2.2%, and 2.1% were applied to labor on line 1, material on line 2, contractor on
17 line 3, and non-labor other on line 4 to develop the annual increase amounts in columns (d),
18 (f), and (h).

19 **Q. Please discuss how the adjustments on Exhibit A-41 (RTB-4), page 2, column (i) were**
20 **determined.**

21 A. As previously discussed, the Company projects the future maintenance needs of each unit.
22 The test period projected O&M expense amount of \$164.252 million reflects that
23 evaluation. Within the test period projected amount of \$164.252 million, there is one

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adjustment that results in a projected amount that differs from the amount that is calculated based solely on inflation.

Q. Please discuss the adjustment that is reflected in the test year projected amount of \$164.252 million.

A. As previously discussed, the Settlement Agreement reached in the Company's 2021 IRP reflects the retirement of Campbell Units 1, 2, and 3 on May 31, 2025. As a result of the retirement of Campbell Units 1, 2, and 3, the Company's projected test year O&M projections are \$7.921 million (\$4.687 million when considering inflation) higher than that recorded in the historical test year. This increase fully explains the \$4.383 million adjustment reflected on Exhibit A-41 (RTB-4), page 2, column (i), line 1.

Q. Please explain the reason for the increase in O&M for Campbell Units 1, 2, and 3.

A. The actual O&M expense for Campbell Units 1, 2, and 3 in 2022 was \$49.344 million as compared to the projected O&M expense for Campbell Units 1, 2, and 3 in the test year of \$57.267 million. This increase is primarily a direct result of accounting for some of the projected test year projects as O&M expense versus capital expenditures. Specifically, a number of the projected test year projects were previously recorded as capital expenditures and will now be recorded as O&M expense due to the May 31, 2025 retirement of Campbell Units 1, 2, and 3.

Q. How has this accounting change impacted the capital expenditures for Campbell Units 1, 2, and 3?

A. This change in accounting has resulted in a \$11.371 million reduction in capital expenditures for Campbell Units 1, 2, and 3 from 2022 to the projected test year. Specifically, 2022 actual capital expenditures for Campbell Units 1, 2, and 3 were

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1 \$12.002 million as compared to the projected test year capital expenditures of
2 \$0.631 million.

3 **ENVIRONMENTAL OPERATIONS**

4 **Q. What are Environmental Operations expenses?**

5 A. Environmental Operations expenses consist of labor and materials supporting the
6 operations of the Company's AQCS. As Federal and State emissions standards require
7 cleaner air, Consumers Energy has installed AQCS to comply with these regulations.
8 Consumers Energy deployed its full suite of AQCS devices in 2016, with 2017 being the
9 first calendar year of operation. Now that the Company has experienced multiple calendar
10 years of operation, the Company anticipates these expenses to remain relatively consistent
11 going forward. However, because the cost to operate and maintain these critical pieces of
12 equipment is directly related to the operation of the coal-fired power plants they support,
13 yearly variances in the total Environmental Operations expense should be expected based
14 on the operation of the coal plants in a given year.

15 **Q. Please explain how the projected Environmental Operations expenses for the**
16 **projected bridge period ending February 29, 2024 and test year ending February 28,**
17 **2025 were calculated.**

18 A. Environmental Operations expenses are a combination of O&M costs related to the
19 environmental equipment at the Karn and Campbell sites. The operations component is
20 primarily calculated using labor costs for operations and environmental waste disposal.
21 The maintenance component is based on a combination of historical and estimated planned
22 maintenance costs on the specific components of environmental equipment. 2022 was the
23 sixth full year of operations of the environmental equipment at both Campbell and Karn,

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1 and the Company now has robust historical data to use in projecting these expenses.
2 However, as reflected on Exhibit A-41 (RTB-4), page 1, line 3, columns (b) and (d), the
3 walk from the 2022 historical expense of \$10.802 million to the projected test year expense
4 of \$5.860 million reflects a cost reduction of \$4.942 million despite inflationary increases.
5 This cost reduction is a direct reflection of the retirement of Karn Units 1 and 2 on May 31,
6 2023.

7 **MAJOR MAINTENANCE**

8 **Q. What are Major Maintenance expenses?**

9 A. Major Maintenance represents O&M projects that are based on asset condition or on
10 historic maintenance intervals over multiple years. To maintain and improve the
11 performance of generating fleet, the Company performs Major Maintenance on a regular
12 basis. However, completion of Major Maintenance work can be influenced by, among
13 other things, actual operations of the generating units, availability of parts and labor, and
14 energy market conditions.

15 **Q. Please explain how the Major Maintenance O&M expenses for the projected bridge**
16 **period ending February 29, 2024 and test year ending February 28, 2025 were**
17 **determined.**

18 A. Major Maintenance expenses are determined by tracking both the historical and future
19 maintenance needs for each site and unit, considering operation safety, unit reliability, and
20 maximum customer value. Individual projects are calculated in a manner similar to capital
21 projects, as discussed earlier in this direct testimony.

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1 **Q. Please identify the 2023 test year Major Maintenance O&M expenses.**

2 A. The Company projects that it will incur \$31.976 million in Major Maintenance O&M
3 expenses during the test year, as identified by Exhibit A-41 (RTB-4), page 1, line 4,
4 column (d). Test year Major Maintenance expense by generating unit is presented on
5 Exhibit A-41 (RTB-4), page 3, column (d).

6 **Q. Why is Consumers Energy spending \$31.976 million in Total Major Maintenance**
7 **O&M expense during the projected test year ending February 28, 2025?**

8 A. The Company is spending the majority of its Total Major Maintenance expense during the
9 test year to maintain reliability. Reliability related Major Maintenance O&M expenses,
10 made predominantly during scheduled outages, allow the plants to avoid equipment issues
11 that would lead to more frequent random outages, exposing customers to potentially more
12 expensive replacement energy at market prices. Minimizing forced outages by maintaining
13 equipment improves the likelihood the unit will be available when needed, thereby
14 minimizing damage that could result in catastrophic failure.

15 **Q. Are Major Maintenance expenses relatively consistent from year to year?**

16 A. No. Although the Company attempts to plan for controlled and consistent levels of Major
17 Maintenance, because Major Maintenance outages occur relatively infrequently, for an
18 individual unit, it is very possible to have significant year-by-year variations in the number,
19 duration, and magnitude of the required Major Maintenance work. Other factors such as
20 unforeseen equipment failure, emerging industry initiatives, unit dispatch, expected power
21 prices, unit performance, and simple timing variations can impact the cost and scheduling
22 of Major Maintenance.

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1 **Q. Is it possible that changes to the Company's forecasted Major Maintenance plan**
2 **could occur?**

3 A. Yes. It is possible that the Company's forecasted Major Maintenance plan could change.
4 Equipment condition can change such that the timing of maintenance activities may need
5 to be accelerated or delayed. The Company attempts to make the best decision in balancing
6 the cost and risks associated with the operation of the equipment and attempts to minimize
7 the cost to customers. Factors such as weather, equipment and labor availability, energy
8 market conditions, and electrical system stability considerations can affect the actual
9 timing of an outage and maintenance spending.

10 **Q. Do Major Maintenance costs vary by individual generating unit(s)?**

11 A. Yes. As the Company's generating units vary in age, size, type, and design, so do the costs
12 to maintain these units. As an example, Major Maintenance of Campbell Unit 3 coal
13 pulverizers (785 MW) would be considerably larger in scope and cost than Major
14 Maintenance of Campbell Unit 1 coal pulverizers (260 MW), which is located on the same
15 site.

16 **Q. Is it common for an electric utility to have different sizes, types, designs, and dispatch**
17 **of generating units in its generation portfolio?**

18 A. Yes. Consumers Energy is not unique in that its fleet contains units of different size, type,
19 and design.

20 **Q. What are the categories of Major Maintenance?**

21 A. Major Maintenance is broken into two categories—outage and non-outage.

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1 **Q. Please describe what is included in the outage major maintenance O&M expense.**

2 A. Outage major maintenance O&M expenses are those associated with major overhauls and
3 require that the generating unit be removed from service for boiler and/or turbine
4 inspections and maintenance. These outages are typically scheduled on a periodic basis
5 and are required by law, insurance providers, and/or industry standards to ensure
6 operational safety and reliability. One example of a major maintenance outage is the
7 periodic disassembly and repair of turbine control and stop valves. The valves control the
8 amount of steam going to the turbine and are needed to control the unit output. During an
9 emergency situation, for example during unit electrical trip, the valves must react very
10 quickly to stop the steam going to the turbine to prevent it from overspeeding.
11 Overspeeding the turbine can result in severe mechanical damage resulting in a very long
12 duration outage to repair, further resulting in increased cost to customers for market priced
13 electricity during the outage. Periodic maintenance of turbine valves is required for
14 personnel and equipment safety. Maintaining the valves on a periodic basis ensures that
15 the clearances and internal components operate as designed and can reliably stop the
16 turbine quickly when needed to prevent turbine or generator damage.

17 **Q. Please describe the work completed in a boiler inspection.**

18 A. Boiler inspections assess the fire (outside) and steam (inside) sides of boiler tubing for
19 weaknesses that will ultimately result in water/steam leaks. After the boiler has been
20 properly opened, ventilated, and cleaned, scaffolding is constructed inside the boiler to
21 provide access to the boiler tubes. Inspections are completed using a number of different
22 methods – visual, non-destructive, and destructive. Visual and non-destructive testing are
23 the most common methods of inspection. Non-destructive testing incorporates the use of

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1 ultrasonic, x-ray, magnetic particle, or like technologies to measure pipe wall thickness.
2 Boiler tubes that are in poor condition or exceed minimum wall thickness are repaired or
3 replaced. After all repairs are complete, boiler tubes are pressure tested. Each boiler is
4 inspected on a specific time schedule, with a one-, two-, or three-year maximum interval.
5 Internal components with known problems are inspected more frequently. External
6 inspections are performed daily by Generation Operations and annually by state inspectors.

7 **Q. Please describe the work completed in a turbine inspection.**

8 A. Turbine inspections consist of disassembling, inspecting, and cleaning the different
9 components of the turbine. During the inspection, worn or damaged parts are repaired or
10 replaced to specific tolerances. Because of the extreme conditions under which these units
11 operate, the demand for uninterrupted power, and dangers associated with operating these
12 large pieces of equipment, industry standards recommend that inspections be completed
13 every seven years.

14 **Q. Please define non-outage maintenance.**

15 A. Non-outage maintenance O&M costs typically do not require the generating unit be
16 removed from service, but they are still critical to the operation of the unit. An example of
17 non-outage maintenance is Mill/Pulverizer maintenance.

18 **Campbell Units 1 and 2 Major Maintenance**

19 **Q. Please describe Campbell Units 1 and 2 Major Maintenance expenses for the**
20 **projected test year ending February 28, 2025.**

21 A. As shown on Exhibit A-41 (RTB-4), page 3, line 2, column (d), Campbell Units 1 and 2
22 Major Maintenance expense is forecasted to be \$1.782 million in the projected test year
23 ending February 28, 2025, and includes:

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- Campbell Units 1 and 2 Periodic Outage Major Maintenance (\$533,333). The scope of this project is to perform boiler maintenance activities during scheduled periodic outages during the projected test year. Expenses include planning, engineering services, materials, and overtime labor;
- Campbell Unit 1 Pulverizer Maintenance (\$433,333). The scope of this project is the procurement of required parts to support the on-going maintenance of the coal pulverizers to maintain their operability. This maintenance work will allow the Company to keep the minimum number of mills in service and, as a result, avoid unit derates due to degraded conditions. The performance of this work will result in safe, reliable, and efficient unit operation;
- Campbell Unit 2 Mill Maintenance — Parts Only Boiler Plant Equipment (\$301,528). The scope of this project is the procurement of required parts to support the on-going maintenance on the coal mill/pulverizers to maintain their operability. This maintenance work will allow the Company to keep the minimum number of mills in service and, as a result, avoid unit derates due to degraded conditions. The performance of this work will result in safe, reliable, and efficient unit operation;
- Five additional Campbell Units 1 and 2 Major Maintenance projects totaling \$183,333, with each individual project representing \$125,000 or less in expenses. Projects include Boiler Testing (mercury and air toxics standards Compliance and Burner Tuning), deaerator and its storage tank (“DAST”) mid-cycle inspection, HEPS, and boiler safety programs FAC inspections; and
- Six Site Common Major Maintenance projects totaling \$768,932 which are shared with Campbell Unit 3. Campbell Units 1 and 2 receive a 43% allocation totaling \$330,641 and Campbell Unit 3 receives a 57% allocation or \$438,291. These projects, all of which represent \$183,333 or less in expense, include groundwater and corrective action monitoring, dry ash landfill engineering support, fuel handling chute liner repairs, deepwater intake screen inspection, and remedial action plan system O&M.

Campbell Unit 3 Major Maintenance

Q. Please describe Campbell Unit 3 Major Maintenance expenses for the projected test year ending February 28, 2025.

A. As shown on Exhibit A-41 (RTB-4), page 3, line 3, column (d), Campbell Unit 3 Major Maintenance expense is forecasted to be \$2.229 million in the test year and includes:

- Campbell Unit 3 Pulverizer Maintenance — Parts Only Mills-Boiler Plant Equipment (\$375,000). The scope of this project is the procurement of required

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parts to support the on-going maintenance on the coal pulverizers to maintain their operability. This maintenance work will allow the Company to keep the minimum number of mills in service and, as a result, avoid unit derates due to degraded conditions. The performance of this work will result in safe, reliable, and efficient unit operation;

- Campbell Unit 3 Periodic Outage Major Maintenance (\$491,608). The scope of this project is to perform boiler, turbine, and BOP maintenance activities during scheduled periodic outages during the project test year. Expenses include planning, engineering services, materials, and overtime labor. Performance of this work will result in improved unit reliability and performance;
- Campbell Unit 3 Boiler Critical Maintenance (\$416,667). The scope of this project is to perform any necessary boiler related repairs during the projected test year;
- Two additional projects for Campbell Unit 3 totaling \$452,671 in expenses, with each individual project representing \$336,033 or less in expenses. These projects include critical motor major maintenance and spray dryer absorber operations and maintenance; and
- Four Site Commons projects that I discussed previously with the Campbell Unit 3 allocation totaling \$438,291.

Karn Units 1 and 2 Major Maintenance

Q. Please describe Karn Units 1 and 2 Major Maintenance expenses for the projected test year ending February 28, 2025.

A. As shown on Exhibit A-41 (RTB-4), page 3, line 4, column (d), Karn Units 1 and 2 Major Maintenance expense is forecasted to be \$0.223 million in the projected test year ending February 28, 2025. This forecasted expense for the projected test year ending February 28, 2025 includes vegetation removal, lined impoundment expense, and groundwater-surface water ("GSI") treatment system. The GSI treatment system is a Site Commons project whose expense is shared with Karn Units 3 and 4.

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Covert Plant Major Maintenance

Q. Please describe the Covert Plant Major Maintenance expenses for the projected test year ending February 28, 2025.

A. As shown on Exhibit A-41 (RTB-4), page 3, line 9, column (d), the Covert Plant Major Maintenance expense is forecasted to be \$6.025 million in the projected test year ending February 28, 2025, and includes:

- Covert Plant LTSA Major Maintenance (\$3,462,054). This is the major maintenance portion of the Mitsubishi negotiated services that cover the planned normal maintenance of each generating unit. The CTGs are a Mitsubishi model M501G1-Kai, the HRSGs are a Deltak model, and the STGs are Mitsubishi. The projected major maintenance expenses are based upon variable fees paid to Mitsubishi for maintenance services which are based on an EFH basis pursuant to the LTSA. Unlike the GE LTSAs for the Jackson and Zeeland plants, there are no milestone payments associated with the fee structure for the Mitsubishi LTSA. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected pre-mature failures of the equipment. This will help maximize availability and, as a result, optimize customer value for the site. Normal maintenance will ensure the Company continues reliable operation of the units;
- Covert Plant Non-LTSA Major Maintenance (\$600,000). This is the major maintenance portion of the Mitsubishi negotiated services that are not covered in the planned normal maintenance of each generating unit. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items not covered under the LTSA that need to be addressed are labor and material to replace the following: blading, ammonia delivery system, SCR catalyst, turbine rotors, cooling towers, and turbine cooling air cooler;
- Covert Plant Capacity Factor Used For Water and Chemicals (\$1,300,000). This item provides for the city water used by the Covert Plant, and for the chemicals required to operate the water purification systems that are used to purify the makeup water prior to use;
- Covert Plant Base Outage Funding – Boiler plant equipment (\$500,000). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages; and

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- Covert Plant HEPS/FAC/DAST Inspections (\$163,333). This project will include the performance of regulatory required HEPS, FAC, and DAST inspections.

Karn Units 3 and 4 Major Maintenance

Q. Please describe Karn Units 3 and 4 Major Maintenance expenses for the projected test year ending February 28, 2025.

A. As shown on Exhibit A-41 (RTB-4), page 3, line 5, column (d), Karn Units 3 and 4 Major Maintenance expense is forecasted to be \$2.017 million in the projected test year ending February 28, 2025, and includes:

- Karn Units 3 and 4 Periodic Outage Major Maintenance (\$425,000). The scope of this project is to perform boiler maintenance activities during scheduled periodic outages during the projected test year. Expenses include planning, engineering services, materials, and overtime labor;
- Karn Unit 3 Cooling Tower Repairs (\$416,667). The scope of this project is to repair as much of the rotted and broken structure as possible and utilize the capital portion of the project to replace fans and other capital items; and
- Fourteen additional projects for Karn Units 3 and 4 totaling \$1,123,333 in expenses, with each individual project representing \$140,000 or less in expenses. These projects include critical motor major maintenance and spray dryer absorber operations and maintenance.

Zeeland Plant Major Maintenance

Q. Please describe Zeeland Plant Major Maintenance expenses for the projected test year ending February 28, 2025.

A. As shown on Exhibit A-41 (RTB-4), page 3, line 7, column (d), Zeeland Plant Major Maintenance expense is forecasted to be \$4.658 million in the projected test year ending February 28, 2025, and includes:

- Zeeland Plant LTSA — Running Maintenance Contract (\$1,925,000). Consumers Energy has a long-term maintenance agreement with GE to perform the major maintenance and capital repairs necessary to maintain unit reliability. This item represents the O&M component of that service agreement;

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- Zeeland Plant Capacity Factor Used for Water and Chemicals (\$1,208,333). This item provides for the city water used by the Zeeland Plant, and for the chemicals required to operate the water purification systems that are used to purify the makeup water prior to use;
- Base Outage — Boiler Plant Equipment (\$600,000). During planned and scheduled periodic outages, inspections and repairs are performed. Base boiler maintenance and outage is needed to complete condition assessment inspections of the boiler and major components, complete repairs on valves and large plant equipment, and complete repairs that are identified during shutdowns and condition assessments; and
- Fourteen additional projects totaling \$924,334 in expenses, with each individual project representing \$208,333 or less in expenses. These include drum level control valve overhaul, excitation and isolation transformer testing and maintenance, HEPS, FAC inspection, large oil-filled transformer maintenance, breaker maintenance, and NERC-required relay testing.

Jackson Plant Major Maintenance

Q. Please describe Jackson Plant Major Maintenance expenses for the projected test year ending February 28, 2025.

A. As shown on Exhibit A-41 (RTB-4), page 3, line 8, column (d), Jackson Plant Major Maintenance expense is forecasted to be \$3.061 million in the projected test year ending February 28, 2025. This forecasted expense consists of:

- Jackson Plant Capacity Factor Used for Water and Chemicals (\$1,400,000). This item provides for the city water used by the Jackson Plant, and for the chemicals required to operate the water purification systems that are used to purify the makeup water prior to use. The projected expense is based upon historical monthly invoice values as well as consideration of the capital project previously discussed in this testimony for site generating water;
- Jackson Plant Non-LTSA Turbine and jet engine repairs (\$400,000). The scope of this major maintenance is to perform jet engine repairs including bushing replacements every 12,000 hours;
- Jackson Plant LTSA — Running Maintenance Contract (\$250,000). Consumers Energy has a long-term maintenance agreement with GE to perform the major maintenance and capital repairs necessary to maintain unit reliability. This item represents the O&M component of that service agreement;

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- Jackson Plant Base Outage - Boiler plant equipment (\$250,000). During planned and scheduled periodic outages, inspections and repairs are performed. Base boiler maintenance and outage is needed to complete condition assessment inspections of the boiler and major components, complete repairs on valves and large plant equipment, and complete repairs that are identified during shutdowns and condition assessments; and
- Eleven additional projects totaling \$760,550 with each individual project representing \$184,167 or less in expenses. These include HEPS, FAC, pre-Filter replacement, high voltage maintenance and NERC testing, and filter house roof maintenance.

LPS Major Maintenance

Q. Please describe LPS Major Maintenance expenses for the projected test year ending February 28, 2025.

A. As shown on Exhibit A-XX (RTB-4), page 3, line 10, column (d), LPS Major Maintenance expense is forecasted to be \$4.422 million in the projected test year ending February 28, 2025, including:

- Fish Barrier Net - Installation, cleaning, and repairs and removal (\$2,040,000). This is a FERC regulatory requirement. The net is installed annually and maintained to meet FERC license requirements (and the requirements of a Settlement Agreement with federal and state natural resource agencies) and minimizes the impact of LPS on fish in Lake Michigan;
- Nine Year Unit Mechanical Interval Inspection & Replacement (\$570,000). The scope of this project is to perform replacement of common wear elements and consumable items associated with the pump/turbine units. This work will include the first nine-year maintenance interval for each of the 6 units as well as up front planning and procurement funding in the first year;
- Reservoir remediation (\$450,000). This is FERC required and related to dam safety to ensure the Company maintains the integrity of the Ludington pond;
- LPS Generator Circuit Breaker ("GCB") Pumping pole maintenance (\$200,000). The scope of this project is to perform maintenance on the Ludington GCBs (Pumping); and
- Twenty additional projects totaling \$1,161,775, with each individual project representing less than \$161,000 in expenses. These include LPS Units 4 and 6 Trash Rack Uplift Study, thrust bearing pad inspection and characterization,

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periodic outage inspections and non-destructive examination, lube oil room repair, Polychlorinated Biphenyl removal and disposal, and powerhouse slope terrace drain cleanout.

Hydro Major Maintenance

Q. Please describe Hydro Major Maintenance expenses for the projected test year ending February 28, 2025.

A. As shown on Exhibit A-41 (RTB-4), page 3, line 11, column (d), Hydro Major Maintenance expense is forecasted to be \$6.298 million in the projected test year ending February 28, 2025, and includes:

- Hydro License Initiatives (\$1,816,667). A FERC requirement, this item resulted from the relicensing of Au Sable, Manistee, and Muskegon River dams, with the main result being that the Company has annual license commitments. License commitments include some recreation, fish payments, and water quality such as upwelling systems licenses;
- Hydro annual FERC Dam Safety Requirements including Part 12 Inspections (\$1,117,833). The scope of this project is to perform the FERC-required dam safety inspections on an annual basis, and the FERC-required Part 12 inspections on each dam every five years (FERC Part 12 regulations are discussed in Mr. Monroe's direct testimony). A similar level of expense is budgeted annually from 2023 through 2025;
- Foote Downstream Concrete Repairs (\$916,667). The scope of this project is to perform correct deficiencies identified in the 2018 Part 12D independent consultant and third-party condition assessment consultant noted multiple deficiencies in their onsite inspections in 2018. These repairs will include repair deteriorated concrete within the tumble bay, perform concrete repairs on the downstream side of the spillway near the openings to the hollow chambers and possibly fill the chambers with concrete, seal the joints between the concrete slabs on the downstream spillway apron to provide protection against scour and undermining of the concrete slabs, and repair/fill the spillway chamber;
- Rogers Right and Left Spillway Wall Repairs (\$416,667). The scope of this project is to perform necessary repairs to the right and left spillway walls. Damage to the right and left walls was sustained during the 2014 flood;
- Alcona Unit 1 concrete repairs (\$250,000). The scope of this project is to investigate the concrete and grout defects and perform repairs. During the Unit 1 2020 outage, concrete cracking was noted above the wicket gate casing but below the head cover. Separation of previously placed grout was also noted

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in the same area. Minor seepage was noted through one of the cracks. There was no seepage noted through any of the previously grouted areas. Repairing the concrete deck support would decrease the probability of water damaging the 7200-volt electrical system and other mechanical and electrical systems in the vicinity;

- Hydro Powerhouse structure Assessments (\$225,000). The scope of this project is to complete a desk top study supplemented with site visits to all 13 river Hydros. Document current high-level conditions of the powerhouse structure, consider high level conceptual repair alternatives, replacement, or removal alternatives. Develop a short- and long-term strategy for buildings that are 85 to 110 years old;
- Hydro Concrete Repairs (\$232,950). The scope of this project is to make necessary repairs to deteriorating concrete at all 13 river hydro facilities. This budgeted amount will allow for the performance of necessary repairs which are identified after spring flows or general deterioration. The identification of large concrete repairs will be considered in the annual budgeting process; and
- Twenty-six additional projects totaling \$1,321,917 with each individual project representing \$175,000 or less in expenses. These projects include Hodenpyl and Tippy Geotech and stability analysis, Tippy Tumble Bay rehabilitation, base outage funding, headgate evaluation and repairs, relief well piezometer cleaning, and condition/risk assessments.

Solar Major Maintenance

Q. Please describe Solar Major Maintenance expenses for the projected test year ending February 28, 2025.

A. As shown on Exhibit A-41 (RTB-4), page 3, line 12, column (d), Solar Major Maintenance expense is forecasted to be \$0.778 million in the projected test year ending February 28, 2025 and includes three projects, all to provide IT support for the Mustang Mile, Muskegon Solar, and Washtenaw Solar IRP solicitation projects. For each of the solar sites, the major maintenance funding includes plant setup in SAP, and payment of the OSISoft PI Historian and Bazefield SCADA overlay license fees.

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Admin and Other Major Maintenance

Q. Please describe Admin and Other Major Maintenance expenses for the projected test year ending February 28, 2025.

A. As shown on Exhibit A-41 (RTB-4), page 3, line 13, column (d), Admin and Other Major Maintenance expense is forecasted to be \$0.150 million in the projected test year ending February 28, 2025 and includes one project: Generation control systems cyber maintenance software support. Specifically, this project provides funding for software maintenance contracts from multiple vendor systems that are not part of the DCS control vendor service contracts.

Classic 7 Major Maintenance

Q. Please describe Classic 7 (B.C. Cobb (“Cobb”), J.C. Weadock (“Weadock”), and J.R. Whiting (“Whiting”) units) Major Maintenance expenses for the projected test year ending February 28, 2025.

A. As shown on Exhibit A-41 (RTB-4), page 3, line 6, column (d), Classic 7 Major Maintenance expense is forecasted to be \$0.334 million in the projected test year ending February 28, 2025.

Q. Why is Consumers Energy projecting to spend \$0.334 million in Major Maintenance on the Classic 7 units in the projected test year ending February 28, 2025?

A. Although the Classic 7 units were retired in 2016, environmental regulations require the continued maintenance of the on-site ash ponds, which includes Cobb landfill and ash pond O&M, Weadock landfill license and inspections, Weadock groundwater and corrective action monitoring, and Whiting ash pond post-closure care.

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**KARN AND CAMPBELL RETENTION AND SEPARATION
PLAN EXPENSE**

Q. Please describe the Karn retention and separation plan.

A. The Karn retention and separation plan is a people strategy that the Company has implemented to ensure that it can retain the necessary qualified employees to operate Karn Units 1 and 2 through their retirement date in May 2023, as well as during the cold and dark time period following retirement. The cold and dark condition refers to the period following plant retirement and prior to plant decommissioning. During this period, limited environmental remediation and perhaps partial demolition is performed. The facility may be physically secured with fencing and other measures to prevent vandalism or theft so as to limit liability risks. On June 7, 2019, the MPSC approved the Company's 2018 IRP Settlement Agreement, which included the retirement of Karn Units 1 and 2 in May 2023. The Company's IRP included detailed support of the Company's need to implement a retention and separation plan to ensure that it could operate the plants safely and reliably through their retirement date.

Q. What is the purpose of the retention component of the Company's plan?

A. The Company has a strong interest in keeping qualified employees working at Karn Units 1 and 2 through their retirement date to ensure safe and reliable operations. The retention component will allow the Company to retain employees that may seek employment at other Company locations or outside of the Company. The Company's ability to hire new employees at Karn Units 1 and 2 will become increasingly difficult given the short remaining lifespan of the units and, to the extent that the Company has the ability to hire new employees, the training time necessary for any new hires will provide a significant

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1 challenge to operating the units both safely and reliably. The retention component utilizes
2 the best practices that the Company employed in retiring the Classic 7.

3 **Q. What is the purpose of the separation component of the Company's plan?**

4 A. When Karn Units 1 and 2 are retired, the Company plans to follow the terms of the
5 collective bargaining agreement for OM&C employees represented by the Utility Workers
6 Union of America ("UWUA"), and the terms of the employee handbook policy and
7 separation plan for non-represented exempt and non-exempt employees. The structure and
8 amount of the severance offers will vary based on employee salary and classification due
9 to differences in the terms of the separation plan covering non-represented employees and
10 the bargaining agreement for UWUA-represented employees. In the event that exempt or
11 non-exempt employees cannot find placement within the Company within 60 miles from
12 their current location, they will be offered involuntary severance in accordance with the
13 terms of the Company's Salaried Separation Plan. The Company's Working Agreement
14 with the UWUA governs separation for OM&C employees who elect to leave the Company
15 rather than accept a new position as well as relocation expenses if they accept a position
16 more than 60 miles away from their current location.

17 **Q. What are the benefit types associated with the Karn retention and separation plan?**

18 A. The Karn retention and separation plan includes three benefit types: retention benefits,
19 severance benefits, and relocation and moving costs.

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1 **Q. Please describe the retention benefits associated with the Karn retention and**
2 **separation plan.**

3 A. The retention benefits associated with the Karn retention and separation plan include three
4 payment components: a signing incentive, annual incentives, and a final retention
5 incentive.

6 Employees received a signing incentive equal to 15% of their base pay if they
7 signed a retention agreement in October 2019. By signing the retention agreement, the
8 employee agreed to forfeit their transfer rights under the current working agreement (for
9 union employees) or under Company policy (for exempt and non-exempt employees). The
10 employee had to stay at Karn until October 31, 2020 to receive the payment; if the
11 employee stayed until that date, the incentive was paid out to the employee within 30 days.
12 If the employee separated from the Company before October 31, 2020, the employee
13 forfeited the signing incentive.

14 Employees receive an annual incentive which graduates from 20% to 30% of their
15 base pay for service each November in years 2019, 2020, and 2021, for staying at Karn and
16 rendering service for the next 12 months. The employee must stay at Karn until October 31
17 of the following year to receive the payment; if the employee stays until that date, the
18 incentive will be paid out to the employee within 30 days. If the employee separates from
19 the Company before October 31 of the next year, the employee forfeits the annual
20 incentive. Eligible employees received their first annual incentive payment in November
21 2020, a second payment in November 2021, and a third payment in November 2022.

22 Employees receive a final retention incentive equal to 60% of their base pay on or
23 about July 1, 2023, if the employee is still at Karn. The payment is intended to incentivize

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1 employees to stay until the plant goes cold and dark and compensate employees for the
2 service they rendered for the eight months (November 2022 through June 2023) prior to
3 the payment.

4 **Q. Please describe the severance benefits associated with the Karn retention and**
5 **separation plan.**

6 A. The severance benefits associated with the Karn retention and separation plan include
7 initial recognition of a severance benefit to be paid, recognition of additional severance
8 earned (one week of pay per year of service), and recognition of the accretion of a final
9 severance benefit.

10 **Q. Why does the Company anticipate the need to make severance payments associated**
11 **with the retirement of Karn Units 1 and 2?**

12 A. The Company is proud of the fact that following the retirement of the Classic 7 in 2016,
13 all Company employees that desired to continue employment with the Company were able
14 to do so. However, the Company is also aware of the fact that it has fewer Company
15 locations (11 within 60 miles of the Karn site) to which employees can relocate, than it did
16 in 2016. As such, the Company has anticipated the need to make severance payments to
17 those employees that cannot find placement. As I previously stated, the Company plans to
18 follow the terms of the collective bargaining agreement for OM&C employees represented
19 by the UWUA, and the terms of the employee handbook policy and separation plan for
20 non-represented exempt and non-exempt employees.

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1 **Q. Please explain the relevant details of the collective bargaining agreement for OM&C**
2 **employees.**

3 A. The collective bargaining agreement for OM&C employees, in Article VII, Section 17, and
4 the Generation Operations Coal Closing Agreement provide that employees will be placed
5 in either a corresponding position, or if none exists, in a vacant position he/she is qualified
6 to perform within 60 miles of his/her current headquarters. Per Article XVII of the
7 collective bargaining agreement, employees who are released due to lack of work, and are
8 not placed as described above, are provided a separation allowance consisting of straight
9 time pay for five regular workdays for each year of continuous service with the
10 Company. Due to the lack of Company locations within 60 miles of Karn Units 1 and 2,
11 as described above, it is anticipated that some employees will be eligible for a separation
12 allowance.

13 **Q. Please describe the Campbell retention plan.**

14 A. The Campbell retention plan is a people strategy that the Company has proposed in its 2021
15 IRP. As previously discussed, the Company's 2021 IRP PCA reflects the retirement of
16 Campbell Units 1, 2, and 3 on May 31, 2025. This retention plan was proposed in order to
17 retain employees through the closure of the three Campbell units. This strategy is
18 necessary to ensure that the Company can operate the Campbell units safely and reliably
19 through their retirement date. This incentive program is the same program that is currently
20 in place for employees at the Karn site.

21 **Q. What is the purpose of the retention component of the Company's plan?**

22 A. For similar reasons described in the Karn retention plan, the Company has a strong interest
23 in keeping qualified employees working at the Campbell site through their retirement date

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1 to ensure safe and reliable operations. The retention component will allow the Company
2 to retain employees that may seek employment at other Company locations or outside of
3 the Company. Similar to the situation at the Karn site, it will be increasingly difficult to
4 hire new employees at the Campbell site given the short remaining lifespan of the units
5 and, to the extent that the Company has the ability to hire new employees, the training time
6 necessary for any new hires will provide a significant challenge to operating the three units
7 both safely and reliably.

8 **Q. What is the purpose of the separation component of the Company's plan?**

9 A. When the Campbell units are retired, the Company plans to follow the terms of the
10 collective bargaining agreement for OM&C employees represented by the UWUA, and the
11 terms of the employee handbook policy and separation plan for non-represented exempt
12 and non-exempt employees. The structure and amount of the severance offers will vary
13 based on employee salary and classification due to differences in the terms of the separation
14 plan covering non-represented employees and the bargaining agreement for
15 UWUA-represented employees. In the event that exempt or non-exempt employees cannot
16 find placement within the Company within 60 miles from their current location, they will
17 be offered involuntary severance in accordance with the terms of the Company's Salaried
18 Separation Plan. The Company's Working Agreement with the UWUA governs separation
19 for OM&C employees who elect to leave the Company rather than accept a new position
20 as well as relocation expenses if they accept a position more than 60 miles away from their
21 current location.

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1 **Q. What are the benefit types associated with the Campbell retention plan?**

2 A. Similar to the Karn retention and separation plan, the Campbell retention plan includes
3 three benefit types: retention benefits, severance benefits, and relocation and moving costs.

4 **Q. Please describe the retention benefits associated with the Campbell retention plan.**

5 A. The retention benefits associated with the Campbell retention plan include three payment
6 components: a signing incentive, periodic incentives, and a final retention incentive. The
7 timeline for retention benefits reflects approval of the Settlement Agreement in the
8 Company's 2021 IRP in June 2022.

9 Employees receive a signing incentive equal to 15% of their base pay if they signed
10 a retention agreement in July 2022. By signing the retention agreement, the employee
11 agreed to forfeit their transfer rights under the current working agreement (for union
12 employees) or under Company policy (for exempt and non-exempt employees). The
13 employee must stay at Campbell until October 31, 2022 to receive the payment; if the
14 employee stayed until that date, the incentive was paid out to the employee within 30 days.
15 If the employee separated from the Company before October 31, 2022, the employee
16 forfeited the signing incentive.

17 Employees receive a periodic incentive which graduates from 20% to 30% of their
18 base pay for service each November in years 2022, 2023, and 2024, for staying at Campbell
19 and rendering service for a certain period. Specifically, for service provided July 2022
20 through October 2022, employees received 20% of their base pay. For service provided
21 November 2022 through October 2023, employees will receive 25% of base pay. For
22 service provided November 2023 through October 2024, employees will receive 30% of
23 base pay. The employee must stay at Campbell until October 31 of the given year to receive

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1 the payment; if the employee stays until that date, the incentive was/will be paid out to the
2 employee within 30 days. If the employee separates from the Company before October 31
3 of the given year, the employee forfeits the annual incentive.

4 Employees receive a final retention incentive equal to 60% of their base pay on or
5 about October 31, 2025, if the employee is still at Campbell. The payment is intended to
6 incentivize employees to stay until the plant goes cold and dark and compensate employees
7 for the service they rendered for the 12 months prior to the payment.

8 **Q. Please describe the severance benefits associated with the Campbell retention plan.**

9 A. The severance benefits associated with the Campbell retention plan include initial
10 recognition of a severance benefit to be paid, recognition of additional severance earned
11 (one week of pay per year of service), and recognition of the accretion of a final severance
12 benefit.

13 **Q. Why does the Company anticipate the need to make severance payments associated**
14 **with the retirement of Campbell Units 1, 2, and 3?**

15 A. The Company is proud of the fact that following the retirement of the Classic 7 in 2016,
16 all Company employees that desired to continue employment with the Company were able
17 to do so. However, the Company is also aware of the fact that it has fewer Company
18 locations (7 within 60 miles of the Campbell site) to which employees can relocate, than it
19 did in 2016. In addition, the Company will also have retired at least two of the Karn
20 generating units in 2023, thereby further reducing the available positions. As such, the
21 Company has anticipated the need to make severance payments to those employees that
22 cannot find placement. As I previously stated, the Company plans to follow the terms of
23 the collective bargaining agreement for OM&C employees represented by the UWUA, and

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1 the terms of the employee handbook policy and separation plan for non-represented exempt
2 and non-exempt employees, as previously discussed for the Karn retention and separation
3 plan.

4 **Q. What are the projected costs for the Company's Karn and Campbell Retention and**
5 **Separation plans?**

6 A. As reflected on Exhibit A-41 (RTB-4), page 1, line 5, the Company incurred actual expense
7 of \$2.339 million in 2022, and is projecting expense of \$14.917 million in the 14-month
8 projected bridge period, and \$18.220 million in the projected test year. The actual 2022
9 expense of \$2.339 million is based upon expense of \$2.339 million for Karn. The
10 14-month projected bridge period expense of \$14.917 million is based upon expense of
11 \$4.704 million for Karn and \$10.213 million for Campbell. The projected test year expense
12 of \$18.220 million is based upon expense of \$4.145 million for Karn and \$14.074 million
13 for Campbell.

14 **Q. Is the Company requesting O&M recovery of the \$18.220 million projected amount**
15 **for the projected test year?**

16 A. No. The Company is not requesting approval of this projected amount in Generation O&M
17 expense. The Company received approval in electric rate case, Case No. U-20697, to defer
18 the recovery of the Karn Retention and Separation O&M amounts for 2021 through 2023.
19 The Company received approval to defer the recovery of the Campbell retention and
20 separation amounts in the Settlement Agreement in its 2021 IRP. As such, the projected
21 amounts for 2022 through the projected test year ending February 28, 2025 are not included
22 in the Total O&M amounts on Exhibit A-41 (RTB-4), page 1, line 6, columns (b), (c) and

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1 (d). Company witness Aponte supports regulatory asset treatment of these expenses in her
2 direct testimony.

3 **Q. Does this conclude your direct testimony?**

4 **A.** Yes, it does.

Schedule: B-5.1

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Summary of Actual and Projected Electric Capital Expenditures
For the years 2022 through 2025
(\$000's)

Case No.: U-21389
Exhibit No.: A-12 (RTB-3)
Schedule: B-5.1
Page: 1 of 10
Witness: RTBlumenstock
Date: May 2023

**Generation Capital Expenditures
(\$000)**

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)
		Historical Year 12 Months Ended 12/31/2022	Projected Bridge Period			Projected Test Year 12 Mos Ending 2/28/2025
		12 Mos Ended 12/31/2023	2 Mos Ending 2/29/2024	14 Mos Ending 2/29/2024		
1	Steam Power Generation					
2	Environmental	\$ 1,108	\$ 3,024	\$ 6	\$ 3,031	\$ 48
3	Routine and Small CapEx	\$ 8,901	\$ 15,016	\$ 1,260	\$ 16,276	\$ 7,173
4	Total Steam Production	\$ 10,009	\$ 18,041	\$ 1,266	\$ 19,307	\$ 7,221
5	Hydraulic Power Generation					
6	Routine and Small CapEx	\$ 26,545	\$ 28,372	\$ 8,289	\$ 36,662	\$ 49,897
7	Total hydraulic production	\$ 26,545	\$ 28,372	\$ 8,289	\$ 36,662	\$ 49,897
8	Pumped Storage Generation					
9	Ludington Overhaul	\$ 8,796	\$ -	\$ -	\$ -	\$ -
10	Routine and Small CapEx	\$ 2,962	\$ 11,558	\$ 2,065	\$ 13,623	\$ 14,137
11	Total Pumped Storage Generation	\$ 11,757	\$ 11,558	\$ 2,065	\$ 13,623	\$ 14,137
12	Other Production Plant					
13	Routine and Small CapEx	\$ 93,060	\$ 1,231,991	\$ 69,392	\$ 1,301,383	\$ 317,717
14	Total Other Production Plant	\$ 93,060	\$ 1,231,991	\$ 69,392	\$ 1,301,383	\$ 317,717
15	SubTotal	\$ 141,372	\$ 1,289,962	\$ 81,012	\$ 1,370,974	\$ 388,972
16	Less Contingency	\$ -	\$ 590	\$ 217	\$ 807	\$ 1,083
17	Grand Total	\$ 141,372	\$ 1,289,372	\$ 80,795	\$ 1,370,168	\$ 387,888

	(a)	(b)	(c)	(d)	(e)
		Projected			
		2 Mos Ending 2/28/2023	12 Mos Ending 2/29/2024	12 Mos Ending 2/28/2025	26 Mos Ending 2/28/2025
1	Steam Power Generation				
2	Environmental	\$ -	\$ 3,031	\$ 48	\$ 3,079
3	Routine and Small CapEx	\$ 4,677	\$ 428,780	\$ 276,630	\$ 710,087
4	Total Steam Production	\$ 4,677	\$ 431,811	\$ 276,679	\$ 713,166
5	Hydraulic Power Generation				
6	Routine and Small CapEx	\$ 2,005	\$ 34,657	\$ 49,897	\$ 86,558
7	Total hydraulic production	\$ 2,005	\$ 34,657	\$ 49,897	\$ 86,558
8	Pumped Storage Generation				
9	Ludington Overhaul			\$ -	\$ -
10	Routine and Small CapEx	\$ 1,151	\$ 12,472	\$ 14,137	\$ 27,759
11	Total Pumped Storage Generation	\$ 1,151	\$ 12,472	\$ 14,137	\$ 27,759
12	Other Production Plant				
13	Routine and Small CapEx	\$ 6,499	\$ 877,703	\$ 48,260	\$ 932,462
14	Total Other Production Plant	\$ 6,499	\$ 877,703	\$ 48,260	\$ 932,462
15	SubTotal	\$ 14,332	\$ 1,356,642	\$ 388,972	\$ 1,759,946
16	Less Contingency	\$ 77	\$ 730	\$ 1,083	\$ 1,890
17	Grand Total	\$ 14,256	\$ 1,355,912	\$ 387,888	\$ 1,758,056

Schedule: B-5.1

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2022 through 2025
(\$000's)

Case No.: U-21389
Exhibit No.: A-12 (RTB-3)
Schedule: B-5.1
Page: 2 of 10
Witness: RTBlumenstock
Date: May 2023

Generation Capital Expenditures											
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Line No.	Description	Projected Bridge Year		Projected Bridge Period				Projected Test Year			
		12 Months Ended 12/31/2022		12 Months Ending 12/31/2023		2 Months Ending 2/29/2024		14 Months Ending 2/29/2024		12 Months Ending 2/28/2025	
1	JHCampbell 1&2	\$	4,067	\$	1,379	\$	14	\$	1,393	\$	272
2	Contractor		\$ 1,825		\$ 902		\$ 11		\$ 913		\$ 211
3	Labor		\$ 642		\$ -		\$ -		\$ -		\$ -
4	Materials		\$ 546		\$ 311		\$ -		\$ 311		\$ -
5	Business Expenses		\$ 2		\$ 165		\$ 3		\$ 168		\$ 61
6	Contingency		\$ -				\$ -		\$ -		\$ -
7	Other (Loadings, Chargebacks)		\$ 1,052				\$ -		\$ -		\$ -
8	JHCampbell 3	\$	7,935	\$	2,418	\$	19	\$	2,437	\$	360
9	Contractor		\$ 3,568		\$ 1,655		\$ 15		\$ 1,671		\$ 279
10	Labor		\$ 1,301		\$ 60		\$ -		\$ 60		\$ -
11	Materials		\$ 1,538		\$ 523		\$ -		\$ 523		\$ -
12	Business Expenses		\$ 7		\$ 180		\$ 4		\$ 184		\$ 81
13	Contingency				\$ -		\$ -		\$ -		\$ -
14	Other (Loadings, Chargebacks)		\$ 1,521		\$ -		\$ -		\$ -		\$ -
15	DEKarn 1&2	\$	(3,312)	\$	-	\$	-	\$	-	\$	-
16	Contractor		\$ (1,680)		\$ -		\$ -		\$ -		\$ -
17	Labor		\$ (460)		\$ -		\$ -		\$ -		\$ -
18	Materials		\$ (291)		\$ -		\$ -		\$ -		\$ -
19	Business Expenses		\$ (2)		\$ -		\$ -		\$ -		\$ -
20	Contingency				\$ -		\$ -		\$ -		\$ -
21	Other (Loadings, Chargebacks)		\$ (880)		\$ -		\$ -		\$ -		\$ -
22	DEKarn 3&4	\$	331	\$	11,220	\$	1,227	\$	12,446	\$	6,542
23	Contractor		\$ 292		\$ 8,245		\$ 1,105		\$ 9,350		\$ 5,882
24	Labor		\$ (115)		\$ 157		\$ 8		\$ 165		\$ 41
25	Materials		\$ 69		\$ 826		\$ -		\$ 826		\$ -
26	Business Expenses		\$ 0		\$ 1,992		\$ 88		\$ 2,080		\$ 494
27	Contingency				\$ -		\$ 25		\$ 25		\$ 125
28	Other (Loadings, Chargebacks)		\$ 85		\$ -		\$ -		\$ -		\$ -
29	Zeeland	\$	21,590	\$	35,256	\$	2,622	\$	37,879	\$	15,286
30	Contractor		\$ 15,391		\$ 31,551		\$ 2,298		\$ 33,848		\$ 13,561
31	Labor		\$ 864		\$ 344		\$ 10		\$ 353		\$ 48
32	Materials		\$ 1,343		\$ 175		\$ 52		\$ 227		\$ 258
33	Business Expenses		\$ 15		\$ 3,152		\$ 214		\$ 3,365		\$ 1,169
34	Contingency				\$ 35		\$ 50		\$ 85		\$ 250
35	Other (Loadings, Chargebacks)		\$ 3,977				\$ -		\$ -		\$ -
36	Jackson Generating Station	\$	32,540	\$	14,062	\$	1,915	\$	15,977	\$	11,720
37	Contractor		\$ 22,830		\$ 12,477		\$ 1,750		\$ 14,226		\$ 10,721
38	Labor		\$ 1,122		\$ 46		\$ 5		\$ 51		\$ 25
39	Materials		\$ 1,686		\$ 75		\$ 49		\$ 124		\$ 263
40	Business Expenses		\$ 42		\$ 1,404		\$ 111		\$ 1,515		\$ 711
41	Contingency				\$ 60		\$ -		\$ 60		\$ -
42	Other (Loadings, Chargebacks)		\$ 6,860		\$ -		\$ -		\$ -		\$ -
43	Covert	\$	-	\$	825,714	\$	3,381	\$	829,095	\$	20,274
44	Contractor		\$ -		\$ 9,765		\$ 3,381		\$ 13,146		\$ 20,274
45	Labor		\$ -		\$ -		\$ -		\$ -		\$ -
46	Materials		\$ -		\$ -		\$ -		\$ -		\$ -
47	Business Expenses		\$ -		\$ 815,949		\$ -		\$ 815,949		\$ -
48	Contingency		\$ -		\$ -		\$ -		\$ -		\$ -
49	Other (Loadings, Chargebacks)		\$ -		\$ -		\$ -		\$ -		\$ -
50	Solar	\$	30,487	\$	355,715	\$	61,465	\$	417,180	\$	269,457
51	Contractor		\$ 24,534		\$ 40,899		\$ 15,801		\$ 56,701		\$ 75,238
52	Labor		\$ 1,225		\$ -		\$ -		\$ -		\$ -
53	Materials		\$ 3,172		\$ -		\$ -		\$ -		\$ -
54	Business Expenses		\$ 63		\$ 41,403		\$ 7,969		\$ 49,372		\$ 18,849
55	Contingency				\$ -		\$ -		\$ -		\$ -
56	Other (Loadings, Chargebacks)		\$ 1,493		\$ 273,413		\$ 37,694		\$ 311,107		\$ 175,371

MICHIGAN PUBLIC SERVICE COMMISSION

Schedule: B-5.1

Case No.: U-21389

Exhibit No.: A-12 (RTB-3)

Schedule: B-5.1

Page: 3 of 10

Witness: RTBlumenstock

Date: May 2023

Consumers Energy Company

Summary of Actual and Projected Electric Capital Expenditures

For the years 2022 through 2025

(\$000's)

Generation Capital Expenditures

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Projected Bridge Year 12 Months Ended 12/31/2022		12 Months Ending 12/31/2023		2 Months Ending 2/29/2024		14 Months Ending 2/29/2024		Projected Test Year 12 Mos Ending 2/28/2025	
57	Classic 7	(120)		-		-					
58	Contractor		(68)		-		-		-		-
59	Labor		(17)		-		-		-		-
60	Materials				-		-		-		-
61	Business Expenses				-		-		-		-
62	Contingency				-		-		-		-
63	Other (Loadings, Chargebacks)		(34)		-		-		-		-
64	Hydros	26,545		28,372		8,289		36,662		49,897	
65	Contractor		16,457		22,594		6,569		29,163		39,612
66	Labor		3,043		37		15		52		92
67	Materials		1,972		-		-		-		-
68	Business Expenses		168		5,360		1,563		6,923		9,484
69	Contingency				382		142		524		708
70	Other (Loadings, Chargebacks)		4,905		-		-		-		-
71	Ludington	11,757		11,558		2,065		13,623		14,137	
72	Contractor		14,073		13,998		2,872		16,870		18,546
73	Labor		1,865		254		137		391		1,008
74	Materials		2,449		-		20		20		(5,628)
75	Business Expenses		48		(2,836)		(970)		(3,806)		176
76	Contingency				113		-		113		-
77	Other (Loadings, Chargebacks)		(6,677)		28		6		34		35
78	Admin and Other	8,443		1,243		9		1,252		979	
79	Contractor		2,345		740		-		740		645
80	Labor		599				-		-		-
81	Materials		953				-		-		-
82	Business Expenses		126		75		-		75		-
83	Contingency						-		-		-
84	Other (Loadings, Chargebacks)		4,420		428		9		437		334
85	Air Quality	1,695		-		-		-		-	
86	Contractor		315				-		-		-
87	Labor		129				-		-		-
88	Materials		867				-		-		-
89	Business Expenses		0				-		-		-
90	Contingency						-		-		-
91	Other (Loadings, Chargebacks)		383				-		-		-
92	RCRA	2,878		-		-		-		-	
93	Contractor		1,595				-		-		-
94	Labor		362				-		-		-
95	Materials		10				-		-		-
96	Business Expenses		5				-		-		-
97	Contingency						-		-		-
98	Other (Loadings, Chargebacks)		907				-		-		-
99	316b	(1,348)		-		-		-		-	
100	Contractor		(730)				-		-		-
101	Labor		(202)				-		-		-
102	Materials		(2)				-		-		-
103	Business Expenses		(9)				-		-		-
104	Contingency						-		-		-
105	Other (Loadings, Chargebacks)		(405)				-		-		-
106	SEEG	(2,865)		-		-		-		-	
107	Contractor		(1,595)				-		-		-
108	Labor		(352)				-		-		-
109	Materials		(10)				-		-		-
110	Business Expenses		(5)				-		-		-
111	Contingency						-		-		-
112	Other (Loadings, Chargebacks)		(903)				-		-		-
113	All Other Environmental	747		3,024		6		3,031		48	
114	Contractor		316		2,487		5		2,492		42
115	Labor		232		192		-		192		-
116	Materials		9		192		-		192		-
117	Business Expenses		2		155		1		156		6
118	Contingency		-				-		-		-
119	Other (Loadings, Chargebacks)		189				-		-		-
120	Total Capital	141,372	141,372	1,289,962	1,289,962	81,012	81,012	1,370,974	1,370,974	388,972	388,972

Schedule: B-5.1

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2022 through 2025
(\$000's)

Case No.: U-21389
Exhibit No.: A-12 (RTB-3)
Schedule: B-5.1
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Witness: RTBlumenstock
Date: May 2023

Generation Capital Expenditures

Line No.	(a) Description	(b) (c) (d) (e) Projected			
		2 Mos Ending 2/28/2023	12 Mos Ending 2/29/2024	12 Mos Ending 2/28/2025	26 Mos Ending 2/28/2025
1	JHCampbell 1&2	\$ 356	\$ 1,037	\$ 272	\$ 1,665
2	Contractor	\$ 516	\$ 397	\$ 211	\$ 1,124
3	Labor	\$ 3	\$ (3)	\$ -	\$ -
4	Materials	\$ (4)	\$ 315	\$ -	\$ 311
5	Business Expenses	\$ (160)	\$ 328	\$ 61	\$ 229
6	Contingency	\$ -	\$ -	\$ -	\$ -
7	Other (Loadings, Chargebacks)	\$ 1	\$ (1)	\$ -	\$ -
8	JHCampbell 3	\$ 1,169	\$ 1,268	\$ 360	\$ 2,797
9	Contractor	\$ 1,694	\$ (23)	\$ 279	\$ 1,950
10	Labor	\$ 8	\$ 52	\$ -	\$ 60
11	Materials	\$ (12)	\$ 535	\$ -	\$ 523
12	Business Expenses	\$ (523)	\$ 707	\$ 81	\$ 264
13	Contingency	\$ -	\$ -	\$ -	\$ -
14	Other (Loadings, Chargebacks)	\$ 2	\$ (2)	\$ -	\$ -
15	DEKarn 1&2	\$ -	\$ -	\$ -	\$ -
16	Contractor	\$ -	\$ -	\$ -	\$ -
17	Labor	\$ -	\$ -	\$ -	\$ -
18	Materials	\$ -	\$ -	\$ -	\$ -
19	Business Expenses	\$ -	\$ -	\$ -	\$ -
20	Contingency	\$ -	\$ -	\$ -	\$ -
21	Other (Loadings, Chargebacks)	\$ -	\$ -	\$ -	\$ -
22	DEKarn 3&4	\$ 1,420	\$ 11,027	\$ 6,542	\$ 18,988
23	Contractor	\$ 1,131	\$ 8,219	\$ 5,882	\$ 15,232
24	Labor	\$ 23	\$ 142	\$ 41	\$ 206
25	Materials	\$ -	\$ 826	\$ -	\$ 826
26	Business Expenses	\$ -	\$ 2,080	\$ 494	\$ 2,574
27	Contingency	\$ 3	\$ 22	\$ 125	\$ 150
28	Other (Loadings, Chargebacks)	\$ 262	\$ (262)	\$ -	\$ -
29	Zeeland	\$ 4,986	\$ 32,892	\$ 15,286	\$ 53,164
30	Contractor	\$ 4,320	\$ 29,528	\$ 13,561	\$ 47,409
31	Labor	\$ 47	\$ 307	\$ 48	\$ 401
32	Materials	\$ 32	\$ 195	\$ 258	\$ 485
33	Business Expenses	\$ 577	\$ 2,789	\$ 1,169	\$ 4,535
34	Contingency	\$ 11	\$ 74	\$ 250	\$ 335
35	Other (Loadings, Chargebacks)	\$ -	\$ -	\$ -	\$ -
36	Jackson Generating Station	\$ 1,475	\$ 14,502	\$ 11,720	\$ 27,697
37	Contractor	\$ 1,309	\$ 12,918	\$ 10,721	\$ 24,948
38	Labor	\$ 5	\$ 46	\$ 25	\$ 76
39	Materials	\$ 14	\$ 111	\$ 263	\$ 388
40	Business Expenses	\$ 142	\$ 1,373	\$ 711	\$ 2,226
41	Contingency	\$ 5	\$ 55	\$ -	\$ 60
42	Other (Loadings, Chargebacks)	\$ -	\$ -	\$ -	\$ -
43	Covert	\$ -	\$ 829,095	\$ 20,274	\$ 849,369
44	Contractor	\$ -	\$ 13,146	\$ 20,274	\$ 33,420
45	Labor	\$ -	\$ -	\$ -	\$ -
46	Materials	\$ -	\$ -	\$ -	\$ -
47	Business Expenses	\$ -	\$ 815,949	\$ -	\$ 815,949
48	Contingency	\$ -	\$ -	\$ -	\$ -
49	Other (Loadings, Chargebacks)	\$ -	\$ -	\$ -	\$ -
50	Solar	\$ 1,732	\$ 415,448	\$ 269,457	\$ 686,638
51	Contractor	\$ 281	\$ 56,420	\$ 75,238	\$ 131,939
52	Labor	\$ -	\$ -	\$ -	\$ -
53	Materials	\$ -	\$ -	\$ -	\$ -
54	Business Expenses	\$ 140	\$ 49,232	\$ 18,849	\$ 68,221
55	Contingency	\$ -	\$ -	\$ -	\$ -
56	Other (Loadings, Chargebacks)	\$ 1,312	\$ 309,796	\$ 175,371	\$ 486,478

MICHIGAN PUBLIC SERVICE COMMISSION

Schedule: B-5.1

Case No.: U-21389

Exhibit No.: A-12 (RTB-3)

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Date: May 2023

Consumers Energy Company
 Summary of Actual and Projected Electric Capital Expenditures
 For the years 2022 through 2025
 (\$000's)

Generation Capital Expenditures

Line No.	(a) Description	(b) (c) (d) (e) Projected			
		2 Mos Ending	12 Mos Ending	12 Mos Ending	26 Mos Ending
		2/28/2023	2/29/2024	2/28/2025	2/28/2025
57	Classic 7	\$ -	\$ -	\$ -	\$ -
58	Contractor	\$ -	\$ -	\$ -	\$ -
59	Labor	\$ -	\$ -	\$ -	\$ -
60	Materials	\$ -	\$ -	\$ -	\$ -
61	Business Expenses	\$ -	\$ -	\$ -	\$ -
62	Contingency	\$ -	\$ -	\$ -	\$ -
63	Other (Loadings, Chargebacks)	\$ -	\$ -	\$ -	\$ -
64	Hydros	\$ 2,005	\$ 34,657	\$ 49,897	\$ 86,558
65	Contractor	\$ 1,718	\$ 27,445	\$ 39,612	\$ 68,776
66	Labor	\$ 6	\$ 46	\$ 92	\$ 144
67	Materials	\$ -	\$ -	\$ -	\$ -
68	Business Expenses	\$ 224	\$ 6,699	\$ 9,484	\$ 16,407
69	Contingency	\$ 57	\$ 466	\$ 708	\$ 1,232
70	Other (Loadings, Chargebacks)	\$ -	\$ -	\$ -	\$ -
71	Ludington	\$ 1,151	\$ 12,472	\$ 14,137	\$ 27,759
72	Contractor	\$ 1,668	\$ 15,202	\$ 18,546	\$ 35,416
73	Labor	\$ 8	\$ 383	\$ 1,008	\$ 1,399
74	Materials	\$ (12)	\$ 33	\$ (5,628)	\$ (5,608)
75	Business Expenses	\$ (515)	\$ (3,291)	\$ 176	\$ (3,630)
76	Contingency	\$ -	\$ 113	\$ -	\$ 113
77	Other (Loadings, Chargebacks)	\$ 2	\$ 32	\$ 35	\$ 69
78	Admin and Other	\$ 38	\$ 1,214	\$ 979	\$ 2,231
79	Contractor	\$ 36	\$ 704	\$ 645	\$ 1,385
80	Labor	\$ -	\$ -	\$ -	\$ -
81	Materials	\$ -	\$ -	\$ -	\$ -
82	Business Expenses	\$ 2	\$ 73	\$ -	\$ 75
83	Contingency	\$ -	\$ -	\$ -	\$ -
84	Other (Loadings, Chargebacks)	\$ -	\$ 437	\$ 334	\$ 771
85	Air Quality	\$ -	\$ -	\$ -	\$ -
86	Contractor	\$ -	\$ -	\$ -	\$ -
87	Labor	\$ -	\$ -	\$ -	\$ -
88	Materials	\$ -	\$ -	\$ -	\$ -
89	Business Expenses	\$ -	\$ -	\$ -	\$ -
90	Contingency	\$ -	\$ -	\$ -	\$ -
91	Other (Loadings, Chargebacks)	\$ -	\$ -	\$ -	\$ -
92	RCRA	\$ -	\$ -	\$ -	\$ -
93	Contractor	\$ -	\$ -	\$ -	\$ -
94	Labor	\$ -	\$ -	\$ -	\$ -
95	Materials	\$ -	\$ -	\$ -	\$ -
96	Business Expenses	\$ -	\$ -	\$ -	\$ -
97	Contingency	\$ -	\$ -	\$ -	\$ -
98	Other (Loadings, Chargebacks)	\$ -	\$ -	\$ -	\$ -
99	316b	\$ -	\$ -	\$ -	\$ -
100	Contractor	\$ -	\$ -	\$ -	\$ -
101	Labor	\$ -	\$ -	\$ -	\$ -
102	Materials	\$ -	\$ -	\$ -	\$ -
103	Business Expenses	\$ -	\$ -	\$ -	\$ -
104	Contingency	\$ -	\$ -	\$ -	\$ -
105	Other (Loadings, Chargebacks)	\$ -	\$ -	\$ -	\$ -
106	SEEG	\$ -	\$ -	\$ -	\$ -
107	Contractor	\$ -	\$ -	\$ -	\$ -
108	Labor	\$ -	\$ -	\$ -	\$ -
109	Materials	\$ -	\$ -	\$ -	\$ -
110	Business Expenses	\$ -	\$ -	\$ -	\$ -
111	Contingency	\$ -	\$ -	\$ -	\$ -
112	Other (Loadings, Chargebacks)	\$ -	\$ -	\$ -	\$ -
113	All Other Environmental	\$ -	\$ 3,031	\$ 48	\$ 3,079
114	Contractor	\$ -	\$ 2,492	\$ 42	\$ 2,534
115	Labor	\$ -	\$ 192	\$ -	\$ 192
116	Materials	\$ -	\$ 192	\$ -	\$ 192
117	Business Expenses	\$ -	\$ 156	\$ 6	\$ 162
118	Contingency	\$ -	\$ -	\$ -	\$ -
119	Other (Loadings, Chargebacks)	\$ -	\$ -	\$ -	\$ -
120	SubTotal	\$ 14,332	\$ 1,356,642	\$ 388,972	\$ 1,759,946
121	Less Contingency	\$ 77	\$ 730	\$ 1,083	\$ 1,890
122	Grand Total	\$ 14,256	\$ 1,355,912	\$ 387,888	\$ 1,758,056

Schedule: B-5.1

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Summary of Actual and Projected Electric Capital Expenditures
For the years 2022 through 2025

(\$000's)

Case No.: U-21389

Exhibit No.: A-12 (RTB-3)

Schedule: B-5.1

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Witness: RTBlumenstock

Date: May 2023

Generation Capital Expenditures

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Period			Projected Test Year
		12 Months Ended 12/31/2022	12 Months Ending 12/31/2023	2 Months Ending 2/29/2024	14 Months Ending 2/29/2024	12 Months Ending 2/28/2025
1	Contractor	\$ 99,467	\$ 145,313	\$ 33,808	\$ 179,120	\$ 185,012
2	Labor	\$ 10,236	\$ 1,090	\$ 174	\$ 1,264	\$ 1,213
3	Materials	\$ 14,311	\$ 2,102	\$ 121	\$ 2,223	\$ (5,107)
4	Business Expenses	\$ 464	\$ 866,998	\$ 8,983	\$ 875,981	\$ 31,030
5	Contingency	\$ -	\$ 590	\$ 217	\$ 807	\$ 1,083
6	Other (Loadings, Chargebacks)	\$ 16,894	\$ 273,869	\$ 37,709	\$ 311,579	\$ 175,740
	Total	\$ 141,372	\$ 1,289,962	\$ 81,012	\$ 1,370,974	\$ 388,972

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)
		12 Months Ending 12/31/2023	2 Months Ending 2/29/2024	Projected		
		12 Months Ending 12/31/2023	2 Months Ending 2/29/2024	14 Months Ending 2/29/2024	12 Months Ending 2/28/2025	26 Months Ending 2/28/2005
1	Contractor	\$ 145,313	\$ 33,808	\$ 179,120	\$ 185,012	\$ 364,133
2	Labor	\$ 1,090	\$ 174	\$ 1,264	\$ 1,213	\$ 2,477
3	Materials	\$ 2,102	\$ 121	\$ 2,223	\$ (5,107)	\$ (2,883)
4	Business Expenses	\$ 866,998	\$ 8,983	\$ 875,981	\$ 31,030	\$ 907,011
5	Contingency	\$ 590	\$ 217	\$ 807	\$ 1,083	\$ 1,890
6	Other (Loadings, Chargebacks)	\$ 273,869	\$ 37,709	\$ 311,579	\$ 175,740	\$ 487,318
	Total	\$ 1,289,962	\$ 81,012	\$ 1,370,974	\$ 388,972	\$ 1,759,946

Schedule: B-5.1

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
 Summary of Projected Electric Capital Expenditures
 For the projected test year ending February 28, 2025
 (\$000's)

Case No.: U-21389
 Exhibit No.: A-12 (RTB-3)
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Generation Capital Expenditures

(a)		(b)	(c)	(d)	(e)	(f)
Line No.	Description	Projected Bridge Period 14 Months Ending 2/29/2024		Projected Test Year 12 Months Ending 2/28/2025		Reference
1	Campbell 1&2 Non-Environmental	\$	1,393	\$	272	A-12 (RTB-3) Page 2 line 1 Columns (d) and (f)
2	Campbell 1&2 "All Other Environmental"		\$ 330		\$ 14	
3	Campbell 3 Non-Environmental	\$	2,437	\$	360	A-12 (RTB-3) Page 2 line 8 Columns (d) and (f)
4	Campbell 3 "All Other Environmental"		\$ 2,700		\$ 18	
5	Karn 1&2 Non-Environmental	\$	-	\$	-	A-12 (RTB-3) Page 2 line 15 Columns (d) and (f)
6	Karn 1&2 "All Other Environmental"		\$ -		\$ -	
7	Total Other Environmental		<u>\$ 3,031</u>		<u>\$ 31</u>	

MICHIGAN PUBLIC SERVICE COMMISSION

Schedule: B-5.1

Consumers Energy Company

Summary of Actual and Projected Electric Capital Expenditures

For the years 2022 through 2025

Generation Capital Projects greater than \$1M

(\$000's)

Case No.: U-21389

Exhibit No.: A-12 (RTB-3)

Schedule: B-5.1

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Witness: RTBlumenstock

Date: May 2023

Generation Capital Expenditures

Line No.	(a) Calendar Year	(b) Tier 1 Portfolio	(c) Tier 2 Portfolio	(d) Project Type	(e) Project Classification	(f) Work Item Description	(g) Projected Contingency ⁽¹⁾	(h) Projected Amount ⁽¹⁾	(i) Actual Amount
1	2022	Coal Generation	Campbell 1	Non-Routine	Environmental	Air Preheater Baskets and Seals	\$ -	\$ 1,470	\$ 1,819
2	2022	Coal Generation	Campbell 1	Routine	Environmental	Pulse Jet Fabric Filter Bag	\$ 200	\$ 1,019	\$ 1,040
3	2022	Coal Generation	Campbell 3	Non-Routine	Condition-based	House Service Air Compressor Replacement	\$ 267	\$ 1,053	\$ 1,207
4	2022	Coal Generation	Campbell 3	Routine	Environmental	Selective Catalytic Reduction Catalyst Management	\$ 500	\$ 1,960	\$ 1,196
5	2022	Coal Generation	Campbell 3	Non-Routine	Condition-based	Campbell Unit 3 Diesel Generator Controls	\$ 19	\$ 187	\$ 1,172
6	2023	Coal Generation	Campbell Site Commons	Non-Routine	Condition-based	North and South Piegion Lake Jetties	\$ -	\$ 740	\$ 1,003
7	2022	Gas/Oil Generation	Karn 3&4 Commons	Non-Routine	Asset Separation	Unit Separation	\$ 500	\$ 7,207	\$ 1,605
8	2022	Gas Generation	Jackson Site Commons	Routine	Condition-based	GE Long Term Service Agreement FFH	\$ -	\$ 8,200	\$ 7,734
9	2022	Gas Generation	Jackson Site Commons	Non-Routine	Condition-based	Reverse Osmosis Pretreatment System	\$ 100	\$ 8,700	\$ 16,237
10	2022	Gas Generation	Jackson Site Commons	Routine	Condition-based	GE Long Term Service Agreement Historical Extra Work	\$ -	\$ 950	\$ 3,920
11	2022	Gas Generation	Zeeland Site Commons	Routine	Condition-based	Long Term Service Agreement - Running Capital Contract	\$ -	\$ 8,160	\$ 7,599
12	2022	Gas Generation	Zeeland Site Commons	Routine	Condition-based	Zeeland Unit 1A Generator Step Up Transformer Rewind	\$ -	\$ 5,500	\$ 8,878
13	2022	Hydro Generation	Croton	Routine	Condition-based	Croton 1 Wicket Gate	\$ 100	\$ 2,150	\$ 4,072
14	2022	Hydro Generation	Croton	Routine	Condition-based	Croton 2 Wicket Gate	\$ 100	\$ 2,150	\$ 4,072
15	2022	Hydro Generation	Hardy	Routine	Safety	Replace powerhouse roof	\$ 100	\$ 1,575	\$ 1,711
16	2022	Hydro Generation	Hardy	Routine	Infrastructure	New Headquarters Building (previously was Croton HQ)	\$ 300	\$ 1,985	\$ 2,740
17	2022	Hydro Generation	Hardy	Non-Routine	Regulatory	Auxiliary Spillway Remediation	\$ 192	\$ 4,700	\$ 3,096
18	2022	Hydro Generation	Hodenpyl	Non-Routine	Condition-based	Spillway Hoist Replacement	\$ 100	\$ 1,900	\$ 1,712
19	2022	Hydro Generation	Hodenpyl	Non-Routine	Condition-based	Transformer Foundation	\$ 250	\$ 2,487	\$ 1,746
20	2022	Hydro Generation	Hodenpyl	Non-Routine	Safety	Electrical Safety Project	\$ -	\$ 2,220	\$ 3,170
21	2022	Hydro Generation	Mio	Non-Routine	Regulatory	Left Retaining Wall Replacement	\$ -	\$ 3,650	\$ 4,300
22	2022	Hydro Generation	Mio	Non-Routine	Safety	Electrical Safety Project	\$ 190	\$ 2,450	\$ 1,677
23	2022	Hydro Generation	Mio	Non-Routine	Regulatory	Mio Downstream reverse filter	\$ -	\$ 570	\$ 1,058
24	2022	Hydro Generation	Ludington Site Commons	Non-Routine	Safety	Powerhouse Roof Wearing Surface and Weather Proofing Replacement	\$ 220	\$ 3,090	\$ 2,325
25	2022	Hydro Generation	Ludington Site Commons	Non-Routine	Safety	Replace Lower Penstock Expansion Joint Chamber Waterstop	\$ 200	\$ 3,878	\$ 4,223
26	2022	Hydro Generation	Ludington Site Commons	Non-routine	Economic	Upgrade and Overhaul	\$ -	\$ 5,370	\$ 8,796
27	2022	Hydro Generation	Ludington Site Commons	Non-Routine	Condition-based	480V Motor Control Center for DLC	\$ -	\$ 845	\$ 1,538
28	2022	Renewables	Solar Commons	Non-Routine	New Generation	Solar - 2021 Bid Event (250 MW)	\$ -	\$ 20,333	\$ 22,789
29	Total 2022 Projects						\$ 3,337	\$ 104,498	\$ 118,365

Note:

(1) Projected amounts were taken from Case No. U-21224

MICHIGAN PUBLIC SERVICE COMMISSION

Schedule: B-5.1

Consumers Energy Company

Summary of Actual and Projected Electric Capital Expenditures
For the years 2022 through 2025

Generation Capital Projects greater than \$1M
(\$000's)

Case No.: U-21389

Exhibit No.: A-12 (RTB-3)

Schedule: B-5.1

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Witness: RTBlumenstock

Date: May 2023

Generation Capital Expenditures

Line No.	(a) Calendar Year	(b) Tier 1 Portfolio	(c) Tier 2 Portfolio	(d) Project Type	(e) Project Classification	(f) Class of Cost Estimate	(g) Engineering Internal or External	(h) Project Bid Issued	(i) Full Internal Budget Approval	(j) Work Item Description	(k) Planned Amount	(l) Project Reduction	(m) Contingency Amount	(n) Projected Amount
1	Bridge Period	Coal Generation	Campbell 3	Routine	Environmental	Class 3	Internal	In Progress	Approved	SCR Catalyst Management	\$ 2,403	\$ 100	\$ -	\$ 2,303
2	Bridge Period	Gas Generation	Covert Commons	Routine	Condition-based	Class 1	NA	Yes	Approved	Long Term Service Agreement - Running capital contract	\$ 9,761	\$ -	\$ -	\$ 9,761
3	Bridge Period	Gas Generation	Covert Commons	Routine	Condition-based	Class 3	NA	No	Approved	Non LTSA Capital - Extras not included in contract	\$ 3,943	\$ -	\$ -	\$ 3,943
4	Bridge Period	Gas Generation	Covert Commons	Non-Routine	Acquisition	Class 1	NA	Yes	Approved	Covert Generating Facility Acquisition	\$ 815,000	\$ -	\$ -	\$ 815,000
5	Bridge Period	Gas/Oil Generation	Karn 3	Non-Routine	Condition-based	Class 3	Internal	No	Approved	Cooling Tower Rebuild	\$ 4,250	\$ 279	\$ -	\$ 3,971
6	Bridge Period	Gas/Oil Generation	Karn 3&4	Non-Routine	Condition-based	Class 3	External	No	Approved	Tank Farm Storage Tank Heating Line Replacement	\$ 1,350	\$ 96	\$ -	\$ 1,254
7	Bridge Period	Gas/Oil Generation	Karn 3&4	Non-Routine	Condition-based	Class 3	External	No	Approved	Sync Wire Replacement	\$ 1,450	\$ -	\$ -	\$ 1,450
8	Bridge Period	Gas/Oil Generation	Karn 3&4 Commons	Non-Routine	Asset Separation	Class 3	External	No	Approved	Unit Separation	\$ 1,790	\$ -	\$ -	\$ 1,790
9	Bridge Period	Gas Generation	Jackson Site Commons	Routine	Condition-based	Class 1	NA	Yes	Approved	GE Long Term Service Agreement FFH	\$ 9,571	\$ -	\$ -	\$ 9,571
10	Bridge Period	Gas Generation	Jackson Site Commons	Non-Routine	Condition-based	Class 3	Internal	No	Approved	7EA Casing replacement & Hot section overhaul	\$ 2,288	\$ 200	\$ -	\$ 2,088
11	Bridge Period	Gas Generation	Jackson Site Commons	Non-Routine	Condition-based	Class 3	External	No	Approved	HRSG Burner Element Isolation Valves Addition	\$ 2,021	\$ -	\$ -	\$ 2,021
12	Bridge Period	Gas Generation	Zeeland Site Commons	Routine	Condition-based	Class 1	NA	Yes	Approved	Long Term Service Agreement - Running Capital Contract	\$ 9,520	\$ -	\$ -	\$ 9,520
13	Bridge Period	Gas Generation	Zeeland Site Commons	Routine	Condition-based	Class 1	NA	Yes	Approved	Milestone Outage Capital to GE - Part of LTSA Contract	\$ 7,870	\$ -	\$ -	\$ 7,870
14	Bridge Period	Gas Generation	Zeeland Site Commons	Non-Routine	Condition-based	Class 1	Internal	Yes	Approved	Phase 2 599 699 345kV Breaker Replacement	\$ 1,302	\$ 79	\$ -	\$ 1,223
15	Bridge Period	Gas Generation	Zeeland Site Commons	Non-Routine	Condition-based	Class 3	External	No	Approved	HRSG Casing Replacement	\$ 2,900	\$ 97	\$ -	\$ 2,803
16	Bridge Period	Gas Generation	Zeeland Site Commons	Routine	Condition-based	Class 2	Internal	No	Approved	LTSA - Extras not included in contract (cranes, mobile equipment)	\$ 3,200	\$ 300	\$ -	\$ 2,900
17	Bridge Period	Gas Generation	Zeeland Site Commons	Non-Routine	Condition-based	Class 2	External	Yes	Approved	Zeeland Unit 4 Field Rewind of Generator Rotor	\$ 1,250	\$ 45	\$ -	\$ 1,205
18	Bridge Period	Gas Generation	Zeeland Site Commons	Non-Routine	Condition-based	Class 2	External	Yes	Approved	Zeeland Unit 3 Field Rewind	\$ 1,250	\$ 45	\$ -	\$ 1,205
19	Bridge Period	Gas Generation	Zeeland Site Commons	Non-Routine	Condition-based	Class 3	Internal	Yes	Approved	Generator Step Up Transformer Replacement (Spare)	\$ 2,883	\$ -	\$ -	\$ 2,883
20	Bridge Period	Gas Generation	Zeeland Site Commons	Non-Routine	Condition-based	Class 1	Internal	Yes	Approved	Zeeland Unit 1 Generator Step Up Transformer Rewin	\$ 4,700	\$ 96	\$ -	\$ 4,604
21	Bridge Period	Hydro Generation	Alcona	Non-Routine	Infrastructure	Class 3	External	No	Approved	Core Wall Remediation Project	\$ 2,600	\$ 1,700	\$ -	\$ 1,910
22	Bridge Period	Hydro Generation	Cooke	Non-Routine	Safety	Class 3	Internal	No	Approved	Spillway Hoist Replacement	\$ 2,100	\$ -	\$ -	\$ 2,100
23	Bridge Period	Hydro Generation	Five Channels	Non-Routine	Regulatory	Class 3	External	No	Approved	Dead Bay and Log Chute Remediation	\$ 2,972	\$ 990	\$ -	\$ 1,982
24	Bridge Period	Hydro Generation	Five Channels	Non-Routine	Regulatory	Class 3	External	No	Approved	Headgate Project	\$ 3,062	\$ 1,080	\$ -	\$ 1,982
25	Bridge Period	Hydro Generation	Hardy	Non-Routine	Regulatory	Class 3	External	No	Approved	Auxiliary Spillway Remediation	\$ 3,459	\$ -	\$ -	\$ 3,459
26	Bridge Period	Hydro Generation	Hodenypl	Non-Routine	Condition-based	Class 3	Internal	No	Approved	Hodenypl 1 Generator Rewind	\$ 3,310	\$ 210	\$ -	\$ 3,101
27	Bridge Period	Hydro Generation	Hodenypl	Non-Routine	Condition-based	Class 3	External	No	Approved	Spillway Hoist Replacement	\$ 2,958	\$ 94	\$ -	\$ 2,864
28	Bridge Period	Hydro Generation	Webber	Non-Routine	Condition-based	Class 1	External	Yes	Approved	Unit 1 Generator Rewind	\$ 1,020	\$ -	\$ -	\$ 1,020
29	Bridge Period	Hydro Generation	Rogers	Non-Routine	Regulatory	Class 4	External	No	Approved	Probable Maximum Flood Project	\$ 2,386	\$ 487	\$ -	\$ 1,899
30	Bridge Period	Hydro Generation	Rogers	Non-Routine	Condition-based	Class 3	Internal	Yes	Approved	Unit 4 Generator Rewind	\$ 2,600	\$ -	\$ -	\$ 2,600
31	Bridge Period	Hydro Generation	Mo	Non-Routine	Safety	Class 2	External	Yes	Approved	Electrical Safety Project	\$ 1,225	\$ 138	\$ -	\$ 1,086
32	Bridge Period	Hydro Generation	Webber	Non-Routine	Infrastructure	Class 2	External	Yes	Approved	Webber Left Downstream Spillway Abutment Wall	\$ 3,200	\$ 225	\$ -	\$ 2,975
33	Bridge Period	Hydro Generation	Ludington Site Commons	Non-Routine	Condition-based	Class 4	External	No	Approved	Oil Water Separator Replacement	\$ 1,263	\$ 100	\$ -	\$ 1,163
34	Bridge Period	Hydro Generation	Ludington Site Commons	Non-Routine	Condition-based	Class 3	External	No	Approved	Unit 1-6 DCS Control Relay Replacement	\$ 1,348	\$ -	\$ -	\$ 1,348
35	Bridge Period	Hydro Generation	Ludington Site Commons	Non-Routine	Safety	Class 3	External	No	Approved	Replace Lower Penstock Expansion Joint Chamber Waterstop	\$ 2,433	\$ 7	\$ -	\$ 2,425
36	Bridge Period	Hydro Generation	Ludington Site Commons	Non-Routine	Safety	Class 1	External	Yes	Approved	Powerhouse Roof Wearing Surface and Weather Proofing Replacement	\$ 2,864	\$ 140	\$ -	\$ 2,724
37	Bridge Period	Hydro Generation	Ludington Site Commons	Non-Routine	Regulatory	Class 1	Internal	Yes	Approved	Replace Barrier Net Panels	\$ 1,089	\$ -	\$ -	\$ 1,089
38	Bridge Period	Renewables	Solar Commons	Non-Routine	New Generation	Class 1/BTA Executed 2021	CE Tech Specs/External Design	Yes	Approved	Solar - 2019 Bid Event (150 MW)	\$ 233,064	\$ -	\$ -	\$ 233,064
39	Bridge Period	Renewables	Solar Commons	Non-Routine	New Generation	Class 1/BTA Executed 2021	CE Tech Specs/External Design	Yes	Approved	Solar - 2020 Bid Event (150 MW)	\$ 122,186	\$ -	\$ -	\$ 122,186
40	Bridge Period	Renewables	Solar Commons	Non-Routine	New Generation	Class 1/Awarded Self-Build 2022	CE Tech Specs/External Design	Yes	Approved	Solar - 2021 Bid Event (Muskegon Solar) (250 MW)	\$ 61,930	\$ -	\$ -	\$ 61,930
41	Total Bridge Period Projects										\$ 1,346,788	\$ 6,597	\$ -	\$ 1,340,191

Note:

(1) Planned amounts were reduced by project reductions and contingency to arrive at the projected amounts

Consumers Energy Company

Summary of Actual and Projected Electric Capital Expenditures

For the years 2022 through 2025

Generation Capital Projects greater than \$1M

(\$000's)

Generation Capital Expenditures

Line No.	(a) Calendar Year	(b) Tier 1 Portfolio	(c) Tier 2 Portfolio	(d) Project Type	(e) Project Classification	(f) Class of Cost Estimate	(g) Engineering Internal or External	(h) Project Bid Issued	(i) Full Internal Budget Approval	(j) Work Item Description	(k) Planned Amount	(l) Project Reduction	(m) Contingency Amount	(n) Projected Amount	
1	Test Year	Gas Generation	Covert Commons	Routine	Condition-based	Class 1	NA	Yes	Approved	Long Term Service Agreement - Running capital contrax	\$ 13,848	-	\$ -	\$ 13,848	
2	Test Year	Gas Generation	Covert Commons	Routine	Condition-based	Class 3	NA	No	Approved	Non Long Term Service Agreemen Capital - Extras not included in contra	\$ 5,510	-	\$ -	\$ 5,510	
3	Test Year	Gas Generation	Jackson Site Commons	Non-Routine	Condition-based	Class 2	External	No	Approved	LM 1 - 6 SAC Extended Life Combusto	\$ 1,338	-	\$ -	\$ 1,338	
4	Test Year	Gas Generation	Jackson Site Commons	Routine	Condition-based	Class 1	NA	Yes	Approved	GE Long Term Service Agreement FFF	\$ 8,245	-	\$ -	\$ 8,245	
5	Test Year	Gas Generation	Zeeland Site Commons	Non-Routine	Condition-based	Class 2	Internal	Yes	Approved	Purchase of Site Spare GSL	\$ 3,917	-	\$ -	\$ 3,917	
6	Test Year	Gas Generation	Zeeland Site Commons	Routine	Condition-based	Class 1	NA	Yes	Approved	Long Term Service Agreement - Running Capital Contra	\$ 8,160	-	\$ -	\$ 8,160	
7	Test Year	Gas/Oil Generation	Karn 3	Non-Routine	Condition-based	Class 3	Internal	No	Approved	Karn 3 Cooling Tower Internal Structure Replacemei	\$ 5,000	-	\$ -	\$ 5,000	
8	Test Year	Hydro Generation	Alcona	Non-Routine	Regulatory	Class 4	Internal	No	Approved	Risk Informed Decision Making Resolution	\$ 2,500	-	\$ -	\$ 2,500	
9	Test Year	Hydro Generation	Alcona	Non-Routine	Infrastructure	Class 3	External	No	Approved	Core Wall Remediation Project	\$ 9,057	\$ -	\$ -	\$ 9,057	
10	Test Year	Hydro Generation	Footle	Non-Routine	Condition-based	Class 3	External	No	Approved	Unit 2 Wicket Gates Replacement Project	\$ 1,253	-	\$ -	\$ 1,253	
11	Test Year	Hydro Generation	Hardy	Routine	Safety	Class 3	External	No	Approved	Electrical Safety Project	\$ 1,500	-	\$ -	\$ 1,500	
12	Test Year	Hydro Generation	Allegan	Non-Routine	Condition-based	Class 3	External	No	Approved	Unit 1 Wicket Gate Replacemen	\$ 1,333	-	\$ -	\$ 1,333	
13	Test Year	Hydro Generation	Five Channels	Non-Routine	Safety	Class 2	External	Yes	Approved	Trash Rack Ergonomics Project	\$ 1,728	-	\$ -	\$ 1,728	
14	Test Year	Hydro Generation	Hardy	Non-Routine	Regulatory	Class 2	External	Yes	Approved	Hardy Splash Wall Replacemen	\$ 3,134	-	\$ -	\$ 3,134	
15	Test Year	Hydro Generation	Webber	Non-Routine	Condition-based	Class 1	External	Yes	Approved	Unit 1 Generator Rewirk	\$ 4,750	-	\$ -	\$ 4,750	
16	Test Year	Hydro Generation	Footle	Non-Routine	Safety	Class 3	External	No	Approved	ADA Ramp Investigation and replacemer	\$ 1,463	-	\$ -	\$ 1,463	
17	Test Year	Hydro Generation	Hodenpyl	Non-Routine	Condition-based	Class 3	External	No	Approved	Downstream Wall	\$ 3,450	-	\$ -	\$ 3,450	
18	Test Year	Hydro Generation	Rogers	Non-Routine	Regulatory	Class 4	External	No	Approved	Powerhouse Left Embankment Retaining Wa	\$ 1,083	-	\$ -	\$ 1,083	
19	Test Year	Hydro Generation	Rogers	Non-Routine	Regulatory	Class 4	External	No	Approved	Probable Maximum Flood Project	\$ 3,272	-	\$ -	\$ 3,272	
20	Test Year	Hydro Generation	Cooke	Non-Routine	Condition-based	Class 3	External	No	Approved	Head Gate Replacement Project	\$ 2,080	-	\$ -	\$ 2,080	
21	Test Year	Hydro Generation	Ludington Site Commons	Non-routine	Condition-based	Class 3	External	No	Approved	Unit 1-6 DCS Control Relay Replacemer	\$ 2,501	-	\$ -	\$ 2,501	
22	Test Year	Hydro Generation	Ludington Site Commons	Routine	Infrastructure	Class 3	External	No	Approved	Administrative Building Addition	\$ 2,714	-	\$ -	\$ 2,714	
23	Test Year	Hydro Generation	Ludington Site Commons	Non-Routine	Regulatory	Class 1	Internal	Yes	Approved	Replace Barrier Net Panel	\$ 1,753	-	\$ -	\$ 1,753	
24	Test Year	Hydro Generation	Ludington Site Commons	Non-Routine	Infrastructure	Class 4	External	No	Approved	Intake Gate and Gate House Mechanical Replaceme	\$ 1,118	-	\$ -	\$ 1,118	
25	Test Year	Renewables	Solar Commons	Non-Routine	New Generation	Class 1/BTA Executed 2021	CE Tech Specs/External Design	Yes	Approved	Solar - 2019 Bid Event (Mustang Mile 150 MW	\$ 49,337	-	\$ -	\$ 49,337	
26	Test Year	Renewables	Solar Commons	Non-Routine	New Generation	Class 1/BTA Executed 2021	CE Tech Specs/External Design	Yes	Approved	Solar - 2020 Bid Event (Washtenaw Solar) (150 MW	\$ 104,980	-	\$ -	\$ 104,980	
27	Test Year	Renewables	Solar Commons	Non-Routine	New Generation	Class 1/Awarded Self-Build 2022	CE Tech Specs/External Design	Yes	Approved	Solar - 2021 Bid Event (Muskegon Solar) (250 MW	\$ 115,140	-	\$ -	\$ 115,140	
28	Total Test Year Projects											\$ 360,164	\$ -	\$ -	\$ 360,164

Note:

(1) Planned amounts were reduced by project reductions and contingency to arrive at the projected amounts

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Summary of the Generation O&M Expense

For the Years 2022 through 2025

(\$000's)

Case No.: U-21389

Exhibit No.: A-41 (RTB-4)

Page: 1 of 3

Witness: RTBlumenstock

Date: May 2023

GENERATION OPERATION AND MAINTENANCE EXPENSES

Line No.	(a) Description	(b) Historical 12 Months Ended 12/31/2022	(c) Projected Bridge Period 14 Months Ending 02/29/2024	(d) Projected Test Year 12 Months Ending 02/28/2025
1	BASE O&M	\$ 106,819	\$ 136,474	\$ 126,416
2	ADJUSTED O&M			
3	Environmental Operations	\$ 10,802	\$ 8,714	\$ 5,860
4	Major Maintenance	\$ 32,411	\$ 27,278	\$ 31,976
5	Retention & Separation	\$ 2,339	\$ 14,917	\$ 18,220
6	TOTAL O&M	\$ 150,030.653	\$ 172,465.3	\$ 164,251.9

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		2022 Actual	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2022	Merit & Inflation 12 Mos Ending Dec 31, 2023	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2023	Merit & Inflation 12 Mos Ending Dec 31, 2024	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2024	Merit & Inflation 2 Mos Ending 2/28/2025	Other Adjustments	Projected O&M 12 Mos Ending 2/28/2025
			(c) * Inflation Rate			(e) * Inflation Rate		(g) * Inflation Rate		(b) + (d) + (f) + (h) + (i)
1	Line Item 1	150,031	150,031	5,851	155,882	3,429	159,311	558	4,383	164,252
	Labor	91,790	91,790	3,580	95,370	2,098	97,468	341	2,699	100,509
	Material	6,931	6,931	270	7,201	158	7,359	26	188	7,573
	Contractor	16,999	16,999	663	17,662	389	18,051	63	474	18,588
	Non-Labor Overheads		0	0	0	0	0	0	0	0
	Non-Labor Other	34,311	34,311	1,338	35,649	784	36,433	128	1,022	37,582

Notes

	2023	2024	2025
4 Annual merit increase			
Annual merit increase	3.9%	2.2%	2.1%
Number of months in the period	12	12	2
Pro-rated merit increase	3.9%	2.2%	0.4%
Annual inflation rates per WP-JCA-xx			
Annual inflation rates	3.9%	2.2%	2.1%
Number of months in the period	12	12	2
Pro-rated inflation rate	3.9%	2.2%	0.4%

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Summary of the Generation Major Maintenance O&M Expense
For the Years 2022 through 2025
(\$000's)

Case No.: U-21389
Exhibit No.: A-41 (RTB-4)
Page: 3 of 3
Witness: RTBlumenstock
Date: May 2023

GENERATION MAJOR MAINTENANCE EXPENSES

Line No.	(a) Description	(b)		(c)		(d)
		Historical 12 Months Ended 12/31/2022		Projected Bridge Period 14 Months Ending 02/29/2024		Projected Test Year 12 Months Ending 02/28/2025
1	Major Maintenance					
2	Campbell 1&2	\$ 3,307	\$	1,875	\$	1,782
3	Campbell 3	\$ 3,196	\$	2,623	\$	2,229
4	Karn 1&2	\$ 6,291	\$	528	\$	223
5	Karn 3&4	\$ 607	\$	1,579	\$	2,017
6	Classic 7	\$ (636)	\$	326	\$	334
7	Zeeland Generating Station	\$ 2,761	\$	5,171	\$	4,658
8	Jackson Generating Station	\$ 7,546	\$	3,237	\$	3,061
9	Covert Generating Stations	\$ -	\$	3,925	\$	6,025
10	Ludington	\$ 4,921	\$	3,571	\$	4,422
11	Hydros	\$ 4,418	\$	4,174	\$	6,298
12	Solar	\$ -	\$	144	\$	778
13	Admin & Other	\$ -	\$	125	\$	150
14	TOTAL Major Maintenance	\$ 32,411	\$	27,278	\$	31,976

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Midcontinent)
Independent System Operator)
(MISO))

Order No. 202-26-16

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 11

Blumenstock 2024 Direct
Testimony

1 STATE OF MICHIGAN
2 BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION
3
4 In the matter of the application Case No. U-21585
5 of CONSUMERS ENERGY COMPANY for
6 authority to increase its rates
7 for the generation and distribution Volume 5
8 of electricity and for other relief.
9 _____/ **PUBLIC**

8 CROSS-EXAMINATION

9 Proceedings held via Microsoft Teams in the
10 above-entitled matter before Sally L. Wallace,
11 Administrative Law Judge with MOAHR, for the Michigan
12 Public Service Commission, Lansing, Michigan, on Monday,
13 November 4, 2024, at 9:03 AM Eastern.

14

15 APPEARANCES:

16 GARY A. GENSCH, JR., ESQ.
17 ANNE M. UITVLUGT, ESQ.
18 EVAN B. KEIMACH, ESQ.
19 SPENCER A. SATTler, ESQ.
20 BRET A. TOTORAItIS, ESQ.
21 MARK R. RUSZKIEWICZ, ESQ.
22 Consumers Energy Company
23 One Energy Plaza
24 Jackson, Michigan 49201

25 On behalf of Consumers Energy Company

22

23

24

25 (Appearances continued)

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21585

DIRECT TESTIMONY

OF

RICHARD T. BLUMENSTOCK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2024

RICHARD T. BLUMENSTOCK
U-21585 DIRECT TESTIMONY

1 **Q. Please state your name and business address.**

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

4 **Q. By whom are you employed?**

5 A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”).

6 **Q. What is your position with Consumers Energy?**

7 A. I am currently the Executive Director of Electric Supply Engineering. I began employment
8 at the Company in May 1994 in the electric transmission planning area where I performed
9 planning studies on the Company’s distribution and transmission systems. In April 2002,
10 I was assigned to the electric operations area where I oversaw engineering operations for
11 the distribution and transmission systems. In August 2009, I was assigned to the fuel
12 supply area where I oversaw the Company’s purchasing and transport functions for fuel
13 for electric generation. In June 2011, I assumed additional responsibilities including
14 oversight of the Company’s interaction in the Midcontinent Independent System Operator,
15 Inc. (“MISO”) markets; wholesale settlements and transactions functions; Power Supply
16 Cost Recovery (“PSCR”) activities; and planning for electric supply necessary to satisfy
17 customers’ energy and capacity needs. In September 2019, I assumed the role of Executive
18 Director of Electric Planning, overseeing the company-wide efforts for all electric
19 planning. In September 2022, I assumed my current position as Executive Director of
20 Electric Supply Engineering.

RICHARD T. BLUMENSTOCK
U-21585 DIRECT TESTIMONY

1 **Q. What are your responsibilities as Executive Director of Electric Supply Engineering?**

2 A. My responsibilities as Executive Director of Electric Supply Engineering include oversight
3 of all activities associated with planning and design for the Company's electric generation
4 portfolio.

5 **Q. What is your formal educational experience?**

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

8 **Q. Have you previously provided testimony before the Michigan Public Service**
9 **Commission ("MPSC" or the "Commission")?**

10 A. Yes, I provided testimony in the following MPSC cases:

- 11 • Case No. U-16045-R: Reconciliation of PSCR Costs and Revenues for the
12 Calendar Year 2010;
- 13 • Case No. U-16432-R: Reconciliation of PSCR Costs and Revenues for the
14 Calendar Year 2011;
- 15 • Case No. U-16890: Approval of a PSCR Plan and for Authorization of Monthly
16 PSCR Factors for the Year 2012;
- 17 • Case No. U-16890-R: Reconciliation of PSCR Costs and Revenues for the
18 Calendar Year 2012;
- 19 • Case No. U-17429: Approval of a Certificate of Necessity for the Thetford
20 Generating Plant pursuant to MCL 460.6s and for related accounting and
21 ratemaking authorizations;
- 22 • Case No. U-17317: Approval of a PSCR Plan and for Authorization of Monthly
23 PSCR Factors for the Year 2014;
- 24 • Case No. U-17317-R: Reconciliation of PSCR Costs and Revenues for the
25 Calendar Year 2014;
- 26 • Case No. U-17752: Authority to amend its renewable energy plan approved in
27 Case Nos. U-15805, U-16543, U-16581, and U-17301;
- 28 • Case No. U-17678: Approval of a PSCR Plan and for Authorization of Monthly
29 PSCR Factors for the Year 2015;

RICHARD T. BLUMENSTOCK
U-21585 DIRECT TESTIMONY

- Case No. U-17678-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2015;
- Case No. U-18250: Application of Consumers Energy for a financing order approving the securitization of qualified costs and related approvals associated with the early termination of the Palisades Nuclear Energy Plant Power Purchase Agreement;
- Case No. U-20134: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief;
- Case No. U-20165: Application of Consumers Energy for approval of its Integrated Resource Plan (“IRP”) pursuant to MCL 460.6t and for other relief;
- Case No. U-20697: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief;
- Case No. U-20963: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief;
- Case No. U-21090: Application of Consumers Energy for Approval of an IRP under MCL 460.6t, certain accounting approvals, and for other relief;
- Case No. U-21224: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief; and
- Case No. U-21389: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief.

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

A. The purpose of my direct testimony is to support the Generation Department (“Generation”) requests in this case, and to provide other information that the Company has committed to provide. Toward that end I will:

- Describe Consumers Energy’s coal-, oil-, and gas-fired generation assets, and its hydroelectric and renewable generation assets, including their projected retirement dates;
- Support the Company’s generation asset strategy to: (1) focus continued investment in those generating units (Zeeland Generating Station (“Zeeland Plant”, “ZGS” or “Zeeland”), New Covert Generating Facility (“Covert Plant” or “Covert”), and Jackson Generating Station (“Jackson Plant”, “JGS” or “Jackson”)) which provide the most long-term economic benefit for customers; and (2) sustain safe and environmentally compliant operations for its coal

RICHARD T. BLUMENSTOCK
U-21585 DIRECT TESTIMONY

generating units (J.H. Campbell (“Campbell”) Units 1, 2, and 3 through their retirement dates;

- Support the periodic outage plans and the Generation Unit Availability and Random Outage Rate (“ROR”) projections for coal generation, oil- and gas-fired peaking generation, and certain hydroelectric power generation, for the projected test year ending February 28, 2026;
- Support the reasonableness and prudence of the capital expenditures for coal generation, oil- and gas-fired peaking generation, and certain hydroelectric power generation for the historical test year ended December 31, 2023, the 14-month bridge period beginning January 1, 2024 and ending February 28, 2025, and the projected test year ending February 28, 2026;
- Support the reasonableness and prudence of the projected investment for Company-owned Solar Generation for the historical test year ended December 31, 2023, the 14-month bridge period beginning January 1, 2024 and ending February 28, 2025, and the projected test year ending February 28, 2026;
- Support the reasonableness and prudence of the Operation and Maintenance (“O&M”) and fuel handling expenses for coal generation, oil- and gas-fired peaking generation, and hydroelectric power for historical test year ended December 31, 2023, the 14-month bridge period beginning January 1, 2024 and ending February 28, 2025, and the projected test year ending February 28, 2026;
- Support the reasonableness and prudence of the O&M expenses for the D.E. Karn (“Karn”) Units 1 and 2 retention and separation incentives for the historical test year ended December 31, 2023;
- Support the reasonableness and prudence of the O&M expenses for the Campbell Units 1, 2, and 3 retention and separation incentives for the historical test year ended December 31, 2023, 14-month bridge period beginning January 1, 2024 and ending February 28, 2025, and the projected test year ending February 28, 2026; and
- Describe the environmental regulations with which the Company’s electric generating fleet must comply.

Q. How is your direct testimony related to the direct testimony of other Company witnesses?

A. Company witness Megan L. Metz’s testimony supports the PSCR costs planned to be incurred, taking into account the periodic outages identified in Exhibit A-41 (RTB-1) and the generating unit availability projections in Exhibit A-42 (RTB-2). Company witness

RICHARD T. BLUMENSTOCK
U-21585 DIRECT TESTIMONY

Metz also supports the capacity value of the Company's generation assets for the seasonal construct in the MISO Planning Resource Auction ("PRA") in Table 2.

Company witness Thomas P. Clark supports the IRP competitive solicitation process and timeline associated with the IRP solar initiative investment, including the build transfer agreements ("BTAs") and their associated projected capital expenditures. In addition, Mr. Clark supports the competitive solicitation process and timeline associated with the proposed battery energy storage system ("BESS") projected capital expenditures.

Company witness Adam J. Monroe supports capital investments in River Hydro facilities, including the Hardy Dam.

Company witness Josnelly C. Aponte supports the regulatory asset balances and amortization for the recovery of retention and separation expenses at both the Karn and Campbell sites in her direct testimony.

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

A. Yes, I am sponsoring the following exhibits:

Exhibit A-41 (RTB-1)	Generating Unit Periodic Outages;
Exhibit A-42 (RTB-2)	Generating Unit Availability Projections;
Exhibit A-12 (RTB-3) Schedule B-5.2	Summary of Actual and Projected Electric Capital Expenditures for the Years 2023 through February 2026;
Exhibit A-43 (RTB-4)	Summary of the Generation O&M Expense for the Years 2023 through February 2026;
Exhibit A-44 (RTB-5)	Muskegon River Economic Impact Studies;
Exhibit A-45 (RTB-6)	Karn Unit 3 Cooling Tower Internal Structure Replacement Concept Approval; and

RICHARD T. BLUMENSTOCK
U-21585 DIRECT TESTIMONY

Exhibit A-46 (RTB-7)

Zeeland Phase I Gas Turbine
Upgrade Concept Approval.

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

A. Yes.

Q. How are the following sections of your direct testimony organized?

A. My direct testimony is divided into four sections. Section I will present exhibits and supporting testimony on the Company's generating assets, its generating asset strategy, and its generating asset projected performance metrics. Included in this section is a discussion of the Company's River Hydro strategy, its compliance with the Settlement Agreement in Case No. U-21224 and the March 1, 2024 Order in Case No. U-21389, the Request for Proposals ("RFP") for the divestiture of the River Hydro facilities, the Company's community outreach activities, and the Company's pursuit of external funding. Section II will describe the environmental regulations with which the Company's electric generating fleet must comply. Section III presents exhibits and supporting testimony for the historical and projected generation capital expenditures. Section IV will present exhibits and supporting testimony for the historical and projected generation O&M expense. This section will include support of the reasonableness and prudence of the O&M expenses for both the Karn Units 1 and 2 retention and separation incentives and also the reasonableness and prudence of the O&M expenses for Campbell Units 1, 2, and 3 retention and separation incentives.

RICHARD T. BLUMENSTOCK
U-21585 DIRECT TESTIMONY

SECTION I

GENERATION ASSETS

Q. Please provide an overview of the Company’s generation assets.

A. As of January 2, 2024, the Company’s total projected owned generation assets for the 2023/2024 Planning Year had a Generator Verification Test Capacity (“GVTC”) of 5,612 MW, comprised of the following units:

TABLE 1

RESOURCE	MICHIGAN LOCATION	IN-SERVICE DATE	RETIREMENT DATE	NET GENERATING CAPABILITY (MW)
COAL FIRED				
JH Campbell 1	West Olive, MI	1962	2025	261
JH Campbell 2	West Olive, MI	1967	2025	356
JH Campbell 3*	West Olive, MI	1980	2025	784 (owned share)
OIL OR GAS FIRED				
Covert	Covert, MI	2004	2040	1089
DE Karn 3	Essexville, MI	1975	2031	594
DE Karn 4	Essexville, MI	1977	2031	606
Zeeland CC	Zeeland, MI	2002	2041	532
Zeeland 1A	Zeeland, MI	2002	2041	159
Zeeland 1B	Zeeland, MI	2002	2041	159
Jackson	Jackson, MI	2002	2041	538
HYDROELECTRIC				
Alcona	Alcona County, MI	1924	n/a	3
Allegan	Allegan County, MI	1936	n/a	1
Cooke	Iosco County, MI	1911	n/a	7
Croton	Newaygo County, MI	1907	n/a	2
Five Channels	Iosco County, MI	1912	n/a	6
Foote	Iosco County, MI	1918	n/a	3
Hardy	Newaygo County, MI	1931	n/a	32
Hodenpyl	Wexford County, MI	1925	n/a	5
Loud	Iosco County, MI	1913	n/a	5
Mio	Oscoda County, MI	1916	n/a	2
Rogers	Mecosta County, MI	1906	n/a	2
Tippy	Manistee County, MI	1918	n/a	6
Webber	Ionia County, MI	1907	n/a	1
RENEWABLES				
Lake Winds	Mason County, MI	2012	2042	101
Cross Winds (Phase I)	Tuscola County, MI	2014	2044	231
Cross Winds (Phase II)	Tuscola County, MI	2018	2048	
Cross Winds (Phase III)	Tuscola County, MI	2018	2048	
Crescent Wind	Jonesville, MI	2021	2051	150
Gratiot Farms Wind	Alma, MI	2021	2051	150
Heartland Farms Wind Park	Ithaca, MI	2024	2054	201
Solar Gardens- GVSU	Grand Rapids, MI	2016	2046	1.6
Solar Gardens- WMU	Kalamazoo, MI	2016	2046	0.6
Cadillac Solar Garden	Cadillac, MI	2021	2051	0.2
Circuit West	Grand Rapids, MI	2019	2049	0.3
ENERGY STORAGE				
Ludington Units 1-6**	Ludington, MI	1973	2069	1169 (owned share)

RICHARD T. BLUMENSTOCK
U-21585 DIRECT TESTIMONY

1 **Q. What does “owned share” mean when used with respect to Campbell Unit 3?**

2 A. The Company owns approximately 93% of Campbell Unit 3. Michigan Public Power
3 Agency and Wolverine Power Supply Cooperative, Inc. own the remaining 7%. Thus, the
4 784 MW capacity reported is 93% of the Campbell Unit 3 GVTC, reflecting the Company’s
5 share of ownership.

6 **Q. What does “owned share” mean when used with respect to Ludington Pumped
7 Storage Plant (“LPS” or “Ludington”) Units 1 through 6?**

8 A. The Company owns 51% of LPS and DTE Electric Company (“DTE”) owns the remaining
9 49%. Thus, the 1,169 MW capacity reported is 51% of the total LPS GVTC, reflecting the
10 Company’s share of ownership.

11 **Q. Do any of the Company’s owned generation units reflect retirement dates which are
12 different from those sponsored in the Company’s previous electric rate case, Case No.
13 U-21389?**

14 A. No. There have been no changes to the retirement dates for the Company’s owned
15 generation units. The only change to the Company’s owned generation units was the
16 addition of Heartland Wind Park which began commercial operation on December 29,
17 2023.

18 **Q. How will the Company continue to meet its load requirements with the retirement of
19 the Campbell units in 2025?**

20 A. The Settlement Agreement approved in the Company’s 2021 IRP reflects the replacement
21 of the Campbell unit capacity through a number of different resources including continued
22 growth of its solar generation assets, demand response, energy waste reduction, the
23 acquisition of the Covert Plant on June 1, 2023, continued operation of Ludington and Karn

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1 Units 3 and 4, and the addition of Zonal Resource Credits (“ZRCs”) by June 1, 2025,
2 through a one-time solicitation approved as part of the Settlement Agreement.

3 The IRP one-time solicitation resulted in the Company’s January 12, 2024, filing
4 of the Tibbits Energy Storage, LLC Power Purchase Agreement (“PPA”), a 100-MW
5 battery storage project which the MPSC approved in its April 11, 2024 Order. The term
6 of the PPA is 20 years, with deliveries expected to commence by May 31, 2025 with an
7 expected PPA termination date of May 31, 2045. The IRP one-time solicitation also
8 resulted in the Company’s May 13, 2024 filing of the Century Oaks Energy Storage LLC
9 PPA, a 200-MW battery storage energy project. The Century Oaks Energy Storage LLC
10 PPA also has a term of 20 years and, with deliveries expected to commence by May 31,
11 2026, with an expected PPA termination date of May 31, 2046.

12 **GENERATION ASSET STRATEGY**

13 **Q. Please describe the Company’s asset strategy for its generating units.**

14 A. The Company’s generation asset strategy is focused on providing safe, reliable, regulatory
15 compliant, and economic energy and capacity for its customers. This strategy will be
16 implemented within the construct of the Company’s clean energy goals and its IRPs, as
17 approved by the MPSC.

18 **Q. How does the Company’s generation asset strategy apply to the Company’s various
19 generating units?**

20 A. Consistent with Consumers Energy’s strategy, the Company’s generating asset investments
21 will focus on onboarding renewable energy resources, including BESSs as well as those
22 generating assets that provide the most economic benefit to customers through their energy
23 and capacity value in the respective MISO markets. In addition, the Company will also

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1 ensure it complies with all state and federal regulations. A detailed discussion of River
2 Hydro compliance is discussed in the direct testimony of Company witness Monroe.

3 Consistent with the approval of the Company's Proposed Course of Action
4 ("PCA") in its 2021 IRP, the Company will concentrate investment in new renewable
5 energy resources, and continue investment in the existing gas-fired units as this strategy
6 will provide the greatest long-term customer benefit. The coal-fired Campbell units will
7 have less investment as they approach retirement in 2025. During 2023, the Company's
8 Zeeland and Jackson Plants produced over 41% of the energy value and approximately
9 25% of the capacity value realized by the Company's electric generating fleet (excluding
10 renewables). The addition of the Covert Plant on June 1, 2023 significantly increased the
11 energy and capacity value for the Company's gas-fired generation. During its seven
12 months of operation during 2023, the Covert Plant contributed almost 28% of the total
13 energy value of the Company's electric generating fleet (excluding renewables) and
14 represents over 18% of the generation fleet's capacity value. As such, the Company's
15 investment focus and associated performance projections have been correspondingly set
16 for these generating units. The figures below reflect the 2023 net energy and capacity value
17 by asset type:

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FIGURE 1

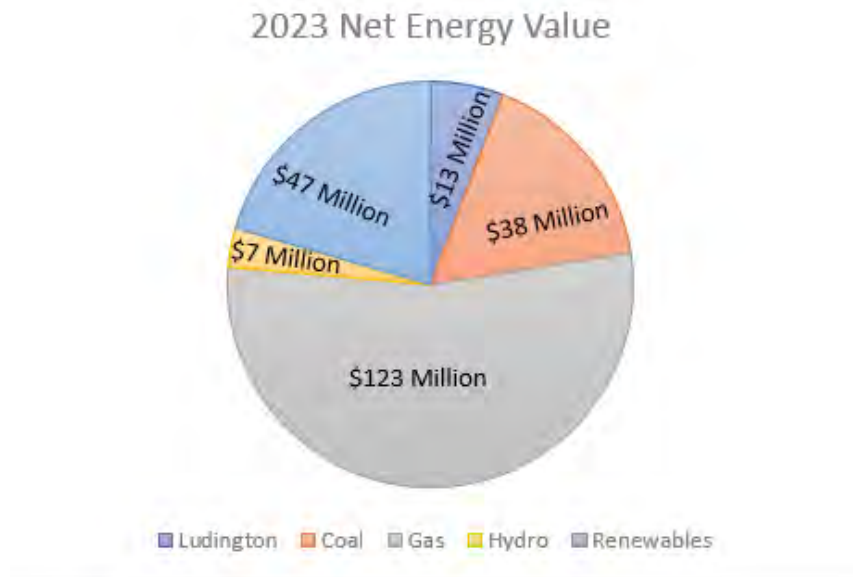
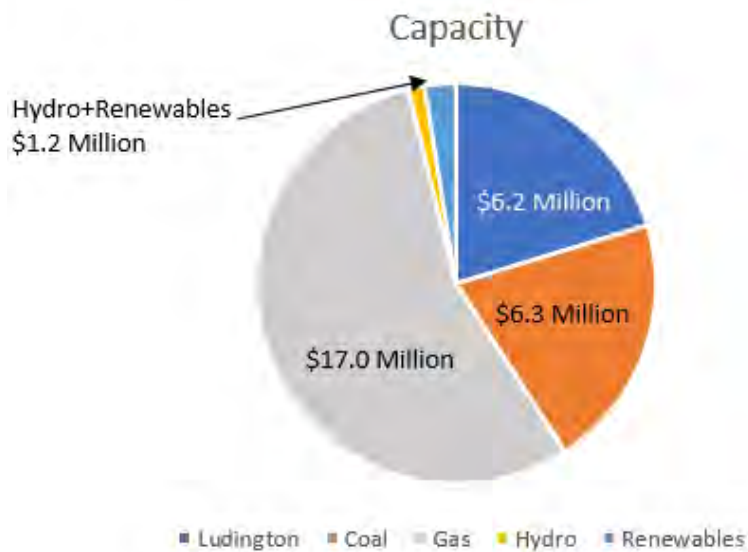


FIGURE 2



1 **Q. How does the Company's generation asset strategy apply to the balance of the**
2 **Company's generating units?**

3 **A.** The Company's generation asset strategy with respect to the remaining generating units
4 will vary depending on each unit's energy value, capacity value, and consistency with the
5 Company's currently approved IRP expected retirement dates. The Company will continue

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1 to maintain its generating units, including the River Hydro facilities, to ensure safe and
2 environmentally compliant operations. With the exception of the River Hydro facilities,
3 I will provide additional detail regarding the Company's generation asset strategy for each
4 of the generating units, or group of generating units, in the portion of this direct testimony
5 describing projected generating unit availability. Company witness Monroe will provide
6 additional detail regarding the Company's generation asset strategy for the River Hydro
7 facilities.

8 **Q. Has the Company's existing generation asset strategy changed as a result of the 2023**
9 **Michigan energy legislation?**

10 A. No. While Public Act ("PA") 235 of 2023 requires the Company to achieve a 50%
11 renewable portfolio standard ("RPS") by 2030, the Company had already committed to an
12 aggressive change in its generation asset portfolio mix through its 2018 and 2021 IRPs.
13 Pursuant to PA 235 of 2023, the Company will be filing a renewable energy plan
14 amendment no later than November 15, 2024, which will reflect its plans to comply with
15 the new renewable energy laws.

16 **PERIODIC OUTAGE PLANS, AVAILABILITY, ROR PROJECTIONS,**
17 **AND NET ENERGY VALUE**

18 **Q. Please describe Exhibit A-41 (RTB-1).**

19 A. Exhibit A-41 (RTB-1) identifies the major outages (28 days or longer in duration) that are
20 scheduled during the projected test year ending February 28, 2026, for the Company's
21 fossil-fueled and Ludington Generating Units. The Company's generation asset strategy
22 is a key input to the scheduling of planned outages, and outage duration directly informs
23 the periodic factors ("PFs") reflected on Exhibit A-42 (RTB-2).

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1 **Q. Please describe Exhibit A-42 (RTB-2), Generating Unit Availability Projections.**

2 A. Exhibit A-42 (RTB-2) details Generating Unit Availability Projections for Consumers
3 Energy's coal generation, peaking generation, and hydraulic power generation for the
4 projected test year beginning March 1, 2025 and ending February 28, 2026. Column (a)
5 identifies Consumers Energy's generating units or category of generating units.
6 Column (b) identifies the five-year historical ROR of the generating unit or category of
7 generating unit. Column (c) identifies the projected ROR of the unit or category of
8 generating unit. Column (d) identifies the PF of the generating unit or category of
9 generating unit. Column (e) identifies the projected availability of the generating unit or
10 category of generating unit. Column (f) identifies the five-year historical Net Energy Value
11 ("NEV") of the generating unit or category of generating unit.

12 **Q. Please define ROR.**

13 A. ROR is a measure of the percent of MWh unavailability due to forced or unplanned
14 generating unit outages and forced or unplanned generating unit de-rates.

15 **Q. What factors cause an increase or decrease in ROR?**

16 A. The frequency and/or duration of a forced or unplanned generating unit outage or
17 generating unit de-rate directly affects ROR. Reducing the frequency and/or duration of
18 forced or unplanned generating unit outages and generating unit de-rates decreases ROR.
19 Conversely, increasing the frequency and/or duration of forced or unplanned generating
20 unit outages and generating unit de-rates degrades ROR.

21 **Q. How are ROR projections for the Generating units developed?**

22 A. The ROR projections for the projected test year ending February 28, 2026 were developed
23 from the five-year (2019-2022) average. These five-year averages were then adjusted to

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1 reflect current operating conditions and projected unit investment. The projected unit
2 investment is developed in accordance with the Company's generation asset strategy.
3 These five-year historical ROR average values are presented in Exhibit A-42 (RTB-2),
4 column (b).

5 **Q. Please define PF.**

6 A. PF is a measure of the percent of lost availability that results from planned outages, planned
7 outage extensions, planned de-rates, and planned de-rate extensions. Planned derates can
8 be taken for a variety of reasons, including the performance of necessary maintenance work
9 which does not require an outage to perform, or the combustion of a coal blend with a
10 lower heat content than is required to achieve the net demonstrated capability of the unit.

11 **Q. What strategy does the Company employ to minimize the impact of planned outages**
12 **on its customers?**

13 A. Consistent with the Company's generation asset strategy, the Company endeavors to
14 schedule planned generating unit outages during periods in which the margin between the
15 generating unit production cost and the projected MISO energy market price is lowest.
16 This strategy results in creating greater total NEV as I will discuss in more detail later in
17 this direct testimony. In general, the projected MISO energy market pricing is lower in the
18 shoulder months of spring and fall due to historically lower demand. However, with the
19 introduction of seasonal capacity in the MISO market, the Company will also consider the
20 impact of outage scheduling on capacity accreditation for the four capacity seasons.
21 Company witness Metz describes seasonal capacity in more detail in her testimony.

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1 **Q. Please define Projected Availability.**

2 A. Projected Availability is a measure of the percent of time that a generating unit or category
3 of generating units is projected to be available to generate electricity.

4 **Q. How is Projected Availability determined for each generating unit or category of**
5 **generating units?**

6 A. The Projected Availability for each generating unit or category of generating unit is
7 calculated as $(100\% - PF) * (100\% - ROR)$. Projected Availability is the key performance
8 metric for implementation of the Company's generation asset strategy for each generating
9 unit or category of generating unit.

10 **Q. How does the Company's generation asset strategy inform Projected Availability?**

11 A. As I previously discussed, the Company's generation asset strategy and associated
12 generation investment will focus on each unit's ability to provide economic value to
13 customers through the unit's ability to produce energy and capacity value in the respective
14 MISO markets. As such, those generating units or category of generating unit providing
15 the greatest amount of economic value to customers will be targeted to achieve the highest
16 projected availabilities.

17 **Q. How can the Company impact Projected Availability for a generating unit?**

18 A. The Company can directly impact Projected Availability for a generating unit by
19 minimizing both PF and ROR for that unit. With respect to minimizing PF, the Company
20 can employ incremental resources during a planned outage to ensure that the critical path
21 for the outage is as short as possible. This strategy could include working 24-hours, seven
22 days a week, for the duration of the outage. Similarly, when a unit experiences an
23 unplanned outage, the Company can employ necessary resources to ensure the unit is

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1 returned to available status as quickly as practical. In addition to minimizing unforced
2 outage length, the Company could invest in a generating unit to increase its reliability and,
3 as a result, decrease the generating unit's projected ROR.

4 **Q. Does the Company attempt to maximize availability for all its generating units or**
5 **category of generating units?**

6 A. No. Consistent with the Company's generation asset strategy, the Company focuses on
7 sustaining availability for those generating units which provide the greatest economic
8 benefit to customers through the energy value provided. The Company's generating units
9 get dispatched by MISO as part of the MISO energy market. Based upon the Company's
10 projected dispatch likelihood for each unit, the Company will rank the generating units
11 from highest economic value to least economic value, and manage the PF and the ROR,
12 and therefore the unit's Availability, to allow for the highest customer value. Or, stated
13 differently, the PF and ROR values may be allowed to be higher (lower unit Availability)
14 for the lower economic value units, and will be managed to lower values (higher unit
15 Availability) for higher economic value units.

16 **Q. How does the Availability projection reflect the customer benefit?**

17 A. An improvement in Availability can translate to a customer benefit in several ways. The
18 immediate benefit is that the generating unit or the category of generating unit is available
19 for dispatch for a greater number of hours throughout the year, likely leading to increased
20 generation, and consequently higher NEV, on an annual basis. Additionally, higher
21 availability increases the ZRCs, increasing the capacity value of the unit.

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1 **Q. How does the Company measure the customer benefit resulting from increased**
2 **generation?**

3 A. The Company utilizes NEV to quantify this customer benefit. At a high level, NEV of a
4 generating unit is the difference between the market value of energy and the cost of
5 producing and supplying that energy. NEV is the net customer benefit of a generator's
6 energy production expressed in dollars. These values are presented in Exhibit A-42
7 (RTB-2), column (f), which identifies five-year (2019-2023) actual NEV amounts.

8 **Q. What can the Company do to positively affect NEV?**

9 A. Typically, economic investments that improve the reliability and availability of the
10 generating unit or category of unit will result in increasing NEV. Economic investments
11 that result in a reduction in the cost to generate will also result in increasing NEV, all else
12 being equal. Positive NEV increases when a generating unit operates more frequently
13 during periods in which market pricing exceeds the cost of production for that unit.
14 Historically, market pricing has tended to be higher in the summer and winter, although
15 there is variability to market conditions. As discussed earlier in my testimony, this is the
16 reason that periodic outages are generally scheduled in the shoulder months of spring and
17 fall. Market prices are typically lower during this time period, thereby reducing the PSCR
18 impact of each scheduled outage.

19 **Q. Does the cost of production vary for the Company's generating units?**

20 A. Yes. The basis for the Company's generation asset strategy is directly related to this
21 actuality. The Company's investment strategy is focused on those units with the lowest
22 variable production costs to maximize NEV for its customers. As the Company
23 strategically invests additional funds in a generating unit to increase its reliability, the

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1 expectation is for the generating unit's reliability to be higher than otherwise possible
2 absent the investment. Higher reliability, in turn, increases the likelihood the unit is
3 available during periods when market prices exceed the production cost of the unit, thus
4 increasing the NEV of the unit.

5 **Q. Why is the measurement of NEV important to the Company and its customers?**

6 A. Positive NEV reflects a direct and immediate reduction to customer power supply costs
7 and consideration of NEV provides a basis for making operational and financial decisions
8 in order to maximize the customer value of the generating unit.

9 **Q. What is another measure the Company uses to evaluate economic projects for its**
10 **generating units?**

11 A. In addition to measuring NEV for a generating unit, the Company also considers the impact
12 a higher availability (specifically ROR) will have on the amount of capacity available from
13 a particular generating unit which receives a monetary credit in the MISO Resource
14 Adequacy Market. Table 2 below summarizes the capacity value of the Company's
15 generating units in the 2023-2024 PRA for Zone 7. Company witness Metz discusses the
16 capacity value of the Company's generating units in the PRA in her testimony in this case.
17 I will discuss the projected impact of the Company's generation asset strategy and
18 associated capital expenditures and major maintenance on the projected availabilities,
19 NEV, and capacity value for each of the generating units later in this direct testimony.

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TABLE 2

RESOURCE	MICHIGAN LOCATION	MISO ISAC ¹ MW	MISO SUMMER SAC ² MW (ZRCs)	CAPACITY VALUE ZONE 7 (SETTLEMENT) ³	CAPACITY VALUE ZONE 7 (75% CONE) ⁴
COAL FIRED					
JH Campbell 1	West Olive, MI	261.3	239.5	\$ 1,311,263	\$ 19,023,796
JH Campbell 2	West Olive, MI	355.5	265.2	\$ 1,451,970	\$ 21,065,181
JH Campbell 3	West Olive, MI	784.3 (owned share)	647.8	\$ 3,546,705	\$ 51,455,596
OIL OR GAS FIRED					
Covert	Covert, MI	1088.6	1028.5	\$ 5,631,038	\$ 81,695,092
DE Karn 3	Essexville, MI	593.5	308.2	\$ 1,687,395	\$ 24,480,727
DE Karn 4	Essexville, MI	606.3	389.3	\$ 2,131,418	\$ 30,922,605
Zeeland CC	Zeeland, MI	532.1	525.3	\$ 2,876,018	\$ 41,725,262
Zeeland 1A	Zeeland, MI	159.4	164.1	\$ 898,448	\$ 13,034,676
Zeeland 1B	Zeeland, MI	158.8	163.5	\$ 895,163	\$ 12,987,018
Jackson	Jackson, MI	537.7	527	\$ 2,885,325	\$ 41,860,295
HYDROELECTRIC					
Alcona	Alcona County, MI	3	3	\$ 16,425	\$ 238,294
Allegan	Allegan County, MI	1.1	1.1	\$ 6,023	\$ 87,374
Cooke	Iosco County, MI	7.1	6.8	\$ 37,230	\$ 540,133
Croton	Newaygo County, MI	2.3	2.3	\$ 12,593	\$ 182,692
Five Channels	Iosco County, MI	6.3	6.1	\$ 33,398	\$ 484,531
Footte	Iosco County, MI	2.9	3	\$ 16,425	\$ 238,294
Hardy	Newaygo County, MI	32.4	31.1	\$ 170,273	\$ 2,470,313
Hodenpyl	Wexford County, MI	4.5	4.5	\$ 24,638	\$ 357,441
Loud	Iosco County, MI	4.9	4.7	\$ 25,733	\$ 373,327
Mio	Oscoda County, MI	1.5	1.6	\$ 8,760	\$ 127,090
Rogers	Mecosta County, MI	2.3	2.4	\$ 13,140	\$ 190,635
Tippy	Manistee County, MI	6.2	6.2	\$ 33,945	\$ 492,474
Webber	Ionia County, MI	1	1	\$ 5,475	\$ 79,431
RENEWABLES					
Lake Winds	Mason County, MI	100.8	14.7	\$ 80,483	\$ 1,167,640
Cross Winds (Phase I, II, III)	Tuscola County, MI	230.6	38.1	\$ 208,598	\$ 3,026,333
Crescent Wind	Jonesville, MI	150	19.2	\$ 105,120	\$ 1,525,081
Gratiot Farms Wind	Alma, MI	150	29.9	\$ 163,703	\$ 2,374,996
Heartland Farms Wind Park	Ithaca, MI	201	36.4	\$ 199,290	\$ 2,891,299
Solar Gardens- GVSU	Grand Rapids, MI	1.6	1.7	\$ 9,308	\$ 135,033
Solar Gardens- WMU	Kalamazoo, MI	0.6	0.6	\$ 3,285	\$ 47,659
Cadillac Solar Garden	Cadillac, MI	0.2	0.2	\$ 1,095	\$ 15,886
Circuit West	Grand Rapids, MI	0.3	0.3	\$ 1,643	\$ 23,829
ENERGY STORAGE					
Ludington Units 1-6	Ludington, MI	1168.8 (owned share)	1138.6	\$ 6,233,835	\$ 90,440,478
¹ ISAC = Intermediate seasonal accredited capacity ² SAC = Seasonal accredited capacity and is converted from ISAC based upon offered availability during RA and non-RA hours ³ 2023-2024 PRA Settlement price of \$15/MW-day for Zone 7. ⁴ 2023-2024 PRA 75% CONE price of \$217.62/MW-day for Zone 7.					

Q. Please provide an overview of the generation asset strategy for Campbell Units 1 and 2.

A. The strategic plan for Campbell Units 1 and 2 is predicated on their planned retirement on May 31, 2025, as reflected in the Company's 2021 IRP Settlement Agreement. The overall remaining life objective for Campbell Units 1 and 2 is to maintain economic dispatch and capacity value from the customer's perspective. The major maintenance expenses in the plan are targeted to provide safe and regulatory compliant units. Critical reliability investments required to keep the units available will be included in the plan. Projects that are targeted to improve reliability will not be considered.

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1 **Q. How will the Company's generation asset strategy for Campbell Units 1 and 2 impact**
2 **their projected performance?**

3 A. It is anticipated that the unit performance will degrade from current performance for both
4 Campbell Units 1 and 2, and this risk will be accepted to limit new investment as the units
5 near retirement. Based upon the Campbell Units 1 and 2 major maintenance projects that
6 I will discuss later in this direct testimony, the Company's generation asset strategy is
7 expected to result in an ROR of 16.00% at Campbell Unit 1 and 15.00% at Campbell Unit 2
8 in the test year, as shown on Exhibit A-42 (RTB-2), lines 1 and 2, column (c). During the
9 five-year historical period from 2019 through 2023, Campbell Unit 1 had an ROR of
10 16.89% and Campbell Unit 2 had an ROR of 30.27% as shown on Exhibit A-42 (RTB-2),
11 lines 1 and 2, column (b).

12 **Q. How is this strategy reflected in the Projected Availability for Campbell Units 1 and 2**
13 **in the test year?**

14 A. The Projected Availabilities for Campbell Units 1 and 2 in the test year are 28.30% and
15 85.00%, respectively, as shown on Exhibit A-42 (RTB-2), lines 1 and 2, column (e). The
16 Projected Availability for Campbell Unit 1 reflects a projected ROR of 16.00% and a PF
17 of 66.30%, as shown on Exhibit A-42 (RTB-2), line 1, columns (c) and (d). The planned
18 Campbell Unit 1 outage for the test year is scheduled to begin on April 1, 2025 and last for
19 60 days, as reflected on Exhibit A-41 (RTB-1), line 5. Projected Availability for Campbell
20 Unit 2 reflects a projected ROR of 15.00% and a PF of 0.00%, as shown on Exhibit A-42
21 (RTB-2), line 2, columns (c) and (d). No outages are planned at Campbell Unit 2 for the
22 test year ending February 28, 2026.

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1 **Q. How does the availability for Campbell Units 1 and 2 translate into customer value?**

2 A. As reflected on Exhibit A-42 (RTB-2), lines 1 and 2, column (f), during the five-year
3 historical period from 2019 through 2023, Campbell Unit 1 had an NEV of \$94.3 million
4 and Campbell Unit 2 had an NEV of \$83.3 million. The 2023 NEV for each of these units
5 was \$6.0 million and \$2.8 million for Campbell Units 1 and 2, respectively.

6 **Q. Please quantify the capacity value for Campbell Units 1 and 2.**

7 A. As reflected in Table 2, the capacity value based upon the settlement price for Zone 7 in
8 the 2023-2024 PRA is \$1.311 million for Campbell Unit 1 and \$1.452 million for Campbell
9 Unit 2. The hypothetical capacity value upon which the Company plans its capacity
10 resources (75% of Cost of New Entry ("CONE")) for Zone 7 in the 2023-2024 PRA is
11 \$19.0 million for Campbell Unit 1 and \$21.1 million for Campbell Unit 2.

12 **Q. Please provide an overview of the generation asset strategy for Campbell Unit 3.**

13 A. The strategic plan for Campbell Unit 3 is predicated on its planned retirement on May 31,
14 2025 as reflected in the Company's 2021 IRP Settlement Agreement. The overall
15 remaining life objective for Campbell Unit 3 is to maintain economic dispatch and capacity
16 value from the customer's perspective. The major maintenance expenses in the plan are
17 targeted to provide safe and regulatory compliant units. Critical reliability investments
18 required to keep the units available will be included in the plan. Capital projects that are
19 targeted to improve reliability will not be considered.

20 **Q. How will the Company's generation asset strategy for Campbell Unit 3 impact its**
21 **projected performance?**

22 A. It is anticipated that unit performance will remain relatively consistent with current
23 performance. Based upon the Campbell Unit 3 capital and major maintenance projects

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discussed later in this testimony, the Company's generation asset strategy is expected to result in an ROR of 8.00% at Campbell Unit 3 in the projected test year, as shown on Exhibit A-42 (RTB-2), line 3, column (c). During the five-year historical period from 2019 through 2023, Campbell Unit 3 had an actual ROR of 14.29%, as shown on Exhibit A-42 (RTB-2), line 3, column (b).

Q. How is this strategy reflected in the Projected Availability for Campbell Unit 3 in the test year?

A. The Projected Availability for Campbell Unit 3 in the test year is 92.00%, as shown on Exhibit A-42 (RTB-2), line 3, column (e). This Availability for Campbell Unit 3 reflects a projected ROR of 8.00% and a PF of 0.00%, as shown on Exhibit A-42 (RTB-2), line 3, columns (c) and (d). No outages are planned at Campbell Unit 3 for the test year ending February 28, 2026.

Q. How does the Campbell Unit 3 Availability translate into customer value?

A. As reflected on Exhibit A-42 (RTB-2), line 3, column (f), during the five-year historical period from 2019 through 2023, Campbell Unit 3 had an NEV of \$347.2 million. The 2023 NEV for Campbell Unit 3 was \$29.2 million.

Q. Please quantify the capacity value for Campbell Unit 3.

A. As reflected in Table 2, the Campbell Unit 3 capacity value based upon the settlement price for Zone 7 in the 2023-2024 PRA is \$3.5 million and the Campbell Unit 3 hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2023-2024 PRA is \$51.5 million.

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1 **Q. Please provide an overview of the generation asset strategy for Karn Units 3 and 4.**

2 A. The strategic plan for Karn Units 3 and 4 is predicated on their planned retirement on
3 May 31, 2031 as reflected in the Company's 2021 IRP Settlement Agreement. The overall
4 remaining life objective for Karn Units 3 and 4 is to maintain economic dispatch and
5 capacity value from the customer's perspective. The capital expenditures and major
6 maintenance expenses in the plan are targeted to provide safe and regulatory compliant
7 units. Critical reliability investments required to keep the units available will be included
8 in the plan. Projects that are targeted to improve reliability will not be considered.

9 **Q. How will the Company's generation asset strategy for Karn Units 3 and 4 impact their**
10 **projected performance?**

11 A. It is anticipated that unit performance for Karn Units 3 and 4 will slightly degrade from
12 current performance. Based upon the Karn Units 3 and 4 capital and major maintenance
13 projects that I will discuss later in this direct testimony, the Company's generation asset
14 strategy is expected to result in an ROR of 18.00% at Karn Unit 3 and 18.00% at Karn
15 Unit 4 in the test year, as shown on Exhibit A-42 (RTB-2), lines 4 and 5, column (c).
16 During the five-year historical period from 2019 through 2023, Karn Unit 3 had an ROR
17 of 38.70% and Karn Unit 4 had an ROR of 24.76%, as shown on Exhibit A-42 (RTB-2),
18 lines 4 and 5, column (b).

19 **Q. How is this strategy reflected in the Projected Availability for Karn Units 3 and 4 in**
20 **the test year?**

21 A. The projected availabilities for Karn Units 3 and 4 in the test year are 72.34% and 71.44%,
22 respectively, as shown on Exhibit A-42 (RTB-2), lines 4 and 5, column (e). The
23 availability for Karn Unit 3 reflects a projected ROR of 18.00% and a PF of 11.78%, as

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1 shown on Exhibit A-42 (RTB-2), line 4, columns (c) and (d). The planned outage for the
2 test year is scheduled to begin on March 1, 2025 and last for 42 days, as reflected on Exhibit
3 A-41 (RTB-1), line 2. The availability for Karn Unit 4 reflects a projected ROR of 18.00%
4 and a PF of 12.88%, as shown on Exhibit A-42 (RTB-2), line 5, columns (c) and (d). The
5 planned outage for the test year is scheduled to begin on March 22, 2025 and last for
6 46 days, as reflected on Exhibit A-41 (RTB-1), line 4.

7 **Q. How does the Projected Availability for Karn Units 3 and 4 translate into customer**
8 **value?**

9 A. As reflected on Exhibit A-42 (RTB-2), lines 4 and 5, column (f), during the five-year
10 historical period from 2019 through 2023, Karn Unit 3 had a NEV of -\$8.1 million and
11 Karn Unit 4 had a NEV of -\$10.4 million. The 2023 NEV for each of these units
12 was -\$1.7 million and -\$0.4 million for Karn Units 3 and 4, respectively.

13 **Q. Please explain why the NEVs for Karn Units 3 and 4 are negative.**

14 A. The NEVs for Karn Units 3 and 4 are negative due to required operation in support of
15 capacity demonstration testing, unit performance validation, and operator training. During
16 this operation, the units are operated as Must-Run resources in the MISO Energy Market
17 and as such, they are price takers. In order to minimize the impact of the required operation
18 of the units, the Company performs those activities during periods in which operation is
19 most economic. However, despite the fact that the NEVs are slightly negative, the units
20 provide a significant amount of capacity value, which far outweighs the negative NEV
21 values. In addition, the Company's ability to have these units dispatched during tight
22 generation days provides reliability benefits for the Company's customers and the MISO
23 energy market.

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1 **Q. Please quantify the capacity value for Karn Units 3 and 4.**

2 A. As reflected in Table 2, the capacity value based upon the settlement price for Zone 7 in
3 the 2023-2024 PRA is \$1.7 million for Karn Unit 3 and \$2.1 million for Karn Unit 4. The
4 hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2023-2024 PRA
5 is \$24.5 million for Karn Unit 3 and \$30.9 million for Karn Unit 4.

6 **Q. Please provide an overview of the generation asset strategy for the Zeeland Plant.**

7 A. The strategic plan for the Zeeland Plant is predicated on plant operation through Planning
8 Year 2040. The overall long-term objective for the Zeeland Plant is to maintain economic
9 dispatch and capacity from the customer's perspective. The units provide significant value
10 to customers in both the energy and resource adequacy markets. The capital expenditures
11 and major maintenance expenses in the plan are targeted to provide a safe, regulatory
12 compliant, and reliable unit. Critical reliability investments required to keep the units
13 available will be included in the plan. Projects that are targeted to improve reliability will
14 be included in the plan if they provide value to customers.

15 **Q. How will the Company's generation asset strategy for the Zeeland Plant impact its**
16 **projected performance?**

17 A. It is anticipated that site performance will remain relatively consistent with current
18 performance. Based upon the Zeeland Plant capital and major maintenance projects that
19 I will discuss later in this testimony, the Company's generation asset strategy is expected
20 to result in an ROR of 4.0% at the Zeeland Plant in the test year, as shown on Exhibit A-42
21 (RTB-2), lines 13 through 15, column (c). During the five-year historical period from 2019
22 through 2023, the Zeeland Plant had ROR values at or below 7.48% for all units, as shown
23 on Exhibit A-42 (RTB-2), lines 13 through 15, column (b).

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1 **Q. How is this strategy reflected in the Projected Availability for the Zeeland Plant in**
2 **the test year?**

3 A. The Projected Availability for the combined cycle generating units (Units 1 and 2) at the
4 Zeeland Plant in the test year is 83.90%, as shown on Exhibit A-42 (RTB-2), line 13,
5 column (e). The Zeeland Combined Cycle (Units 3, 4, and 5) Generating Unit availability
6 is based upon a projected ROR of 4.0% and a PF of 12.60%, as shown on Exhibit A-42
7 (RTB-2), line 13, columns (c) and (d). The Projected Availabilities for each of the simple
8 cycle generating units at the Zeeland site in the projected test year are 86.79%, as shown
9 on Exhibit A-42 (RTB-2), lines 14 and 15, column (e). Each of the Zeeland simple cycle
10 generating unit Projected Availabilities are based upon projected RORs of 4.0% and PFs
11 of 9.59%, as shown on Exhibit A-42 (RTB-2), lines 14 and 15, columns (c) and (d). There
12 are no outages greater than 28 days scheduled for the Zeeland combined cycle units
13 (Units 3, 4, and 5) in the projected test year ending February 28, 2026, however there are
14 several shorter duration outages of 10 days each scheduled in May and October. The
15 planned outage for the test year for Zeeland Unit 1 is scheduled to begin on March 10, 2025
16 and last for 34 days, as reflected on Exhibit A-41 (RTB-1), line 3. The planned outage for
17 the test year for Zeeland Unit 2 is scheduled to begin on April 21, 2025 and last for 34
18 days, as reflected on Exhibit A-41 (RTB-1), line 6. These outages are scheduled during
19 periods in which energy prices are projected to be lower, thereby reducing the impact of
20 the outages on customers. In addition, the outages are scheduled to maximize future
21 capacity attribution for the units given the MISO seasonal resource adequacy construct.

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1 **Q. How does the Zeeland Plant Projected Availability translate into customer value?**

2 A. As reflected on Exhibit A-42 (RTB-2), lines 13 through 15, column (f), during the five-year
3 historical period from 2019 through 2023, the Zeeland Plant provided a total NEV of
4 \$220.5 million. The 2023 NEV for Zeeland was \$49.4 million.

5 **Q. Please quantify the capacity value for the Zeeland Plant.**

6 A. As reflected in Table 2, the Zeeland Plant capacity value based upon the settlement price
7 for Zone 7 in the 2023-2024 PRA is \$4.7 million and the Zeeland Plant hypothetical
8 capacity value based upon 75% of CONE for Zone 7 in the 2023-2024 PRA is
9 \$67.7 million.

10 **Q. Please provide an overview of the generation asset strategy for the Jackson Plant.**

11 A. The strategic plan for the Jackson Plant is predicated on plant operation through Planning
12 Year 2040. The overall long-term objective for the Jackson Plant is to maintain economic
13 dispatch and capacity from the customer's perspective. The units provide significant value
14 to customers in both the energy and resource adequacy markets. The capital expenditures
15 and major maintenance expenses in the plan are targeted to provide a safe, regulatory
16 compliant, and reliable unit. Critical reliability investments required to keep the units
17 available will be included in the plan. Projects that are targeted to improve reliability will
18 be included in the plan if they provide value to customers.

19 **Q. How will the Company's generation asset strategy for the Jackson Plant impact its
20 projected performance?**

21 A. It is anticipated that site performance will remain relatively consistent with current
22 performance. Based upon the Jackson Plant capital and major maintenance projects that
23 I will discuss later in this direct testimony, the Company's generation asset strategy is

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1 expected to result in an ROR of 4.50% at the Jackson Plant in the test year, as shown on
2 Exhibit A-42 (RTB-2), line 16, column (c). During the five-year historical period from
3 2019 through 2023, the Jackson Plant had an actual ROR of 8.22%, as shown on Exhibit
4 A-42 (RTB-2), line 16, column (b).

5 **Q. How is this strategy reflected in the Projected Availability for the Jackson Plant in**
6 **the test year?**

7 A. The Projected Availability for all of the generating units at the Jackson site in the test year
8 is 81.63%, as shown on Exhibit A-42 (RTB-2), line 16, column (e). The Projected
9 Availability for the Jackson site reflects a projected ROR of 4.50% and a PF of 14.52%, as
10 shown on Exhibit A-42 (RTB-2), line 16, columns (c) and (d). There are no major planned
11 outages in excess of 28 days for the Jackson units in the test year, however a short 12-day
12 outage is scheduled to begin October 10, 2025. In addition, several derates are scheduled
13 to perform inspections and maintenance on various generating units in April and September
14 2025.

15 **Q. How does the Jackson Plant Projected Availability translate into customer value?**

16 A. As reflected on Exhibit A-42 (RTB-2), line 16, column (f), during the five-year historical
17 period from 2019 through 2023, the Jackson units provided a total NEV of \$158.4 million.
18 The 2023 NEV for the Jackson Plant was \$24.1 million.

19 **Q. Please quantify the capacity value for the Jackson Plant.**

20 A. As reflected in Table 2, the Jackson Plant capacity value based upon the settlement price
21 for Zone 7 in the 2023-2024 PRA is \$2.9 million and the Jackson Plant hypothetical
22 capacity value based upon 75% of CONE for Zone 7 in the 2023-2024 PRA is
23 \$41.9 million.

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1 **Q. How will the Company's generation asset strategy for the Covert Plant impact its**
2 **projected performance?**

3 A. It is anticipated that site performance will remain relatively consistent with past
4 performance under different ownership. Based upon the Covert Plant capital and major
5 maintenance projects that I will discuss later in this direct testimony, the Company's
6 generation asset strategy is expected to result in an ROR of 7.00% for all three units at the
7 Covert Plant in the test year, as shown on Exhibit A-42 (RTB 2), lines 17 through 19,
8 column (c).

9 **Q. How is this strategy reflected in the Projected Availability for the Covert Plant in the**
10 **test year?**

11 A. The Projected Availability for each of the combined cycle generating units at the Covert
12 Plant in the test year ranges from 75.16% to 82.55%, as shown on Exhibit A-42 (RTB-2),
13 lines 17 through 19, column (e). The Covert Unit 1 unit availability of 80.77% is based
14 upon projected ROR of 7.00% and a PF of 13.15%, as shown on Exhibit A-42 (RTB-2),
15 line 17, columns (c) and (d), the Covert Unit 2 unit availability of 82.55% is based upon
16 projected ROR of 7.00% and a PF of 11.23%, as shown on Exhibit A-42 (RTB-2), line 18,
17 columns (c) and (d), and the Covert Unit 3 unit availability of 75.16% is based upon
18 projected ROR of 7.00% and a PF of 19.18%, as shown on Exhibit A-42 (RTB-2), line 18,
19 columns (c) and (d). The Company will conduct major inspections at all three of the Covert
20 Units during the bridge period/test year. The planned outage for the test year for Covert
21 Unit 1 is scheduled to begin on February 1, 2026 and last for 59 days (beyond the test year),
22 as reflected on Exhibit A-41 (RTB-1), line 8. The planned outage for the test year for
23 Covert Unit 2 is scheduled to begin on February 1, 2025 and last for 59 days, as reflected

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1 on Exhibit A-41 (RTB-1), line 1. The planned outage for the test year for Covert Unit 3 is
2 scheduled to begin on November 1, 2025 and last for 59 days, as reflected on Exhibit A-41
3 (RTB-1), line 7. These outages are scheduled for periods in which energy prices are
4 projected to be lower, thereby reducing the impact of the outages on customers. In addition,
5 the outages are scheduled to maximize future capacity attribution for the units given the
6 MISO seasonal resource adequacy construct.

7 **Q. How does the Covert Plant Projected Availability translate into customer value?**

8 A. As reflected on Exhibit A-42 (RTB-2), lines 17 through 19, column (f), during the
9 seven-month historical period in 2023, the Covert units provided a total NEV of
10 \$49.4 million.

11 **Q. Please quantify the capacity value for the Covert Plant.**

12 A. As reflected in Table 2, the Covert Plant capacity value based upon the settlement price for
13 Zone 7 in the 2023-2024 PRA is \$5.6 million and the Covert Plant hypothetical capacity
14 value based upon 75% of CONE for Zone 7 in the 2023-2024 PRA is \$81.7 million.

15 **Q. Please provide an overview of the generation asset strategy for the River Hydro units.**

16 A. A full discussion of the Company's River Hydro generation asset strategy is included in
17 the direct testimony of Company witness Monroe. In addition, Company witness Monroe
18 will discuss the capital investments for the River Hydro projects which are necessary for
19 continued safe and reliable operation. Regardless of the future of the River Hydro
20 facilities, Consumers Energy will maintain safe operation of its hydroelectric dams as long
21 as they are licensed by the Company. As all of the River Hydro facilities are currently
22 licensed through at least 2034, the Company needs to continue to invest in these assets to

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maintain its licenses and the Company's commitment to dam safety as long as the Company holds the Federal Energy Regulatory Commission ("FERC") licenses.

Q. Did the Order in the Company's 2023 Electric Rate Case (Case No. U-21389) establish any specific requirements for the River Hydro facilities?

A. Yes. Paragraph D on page 309 of the March 1, 2024 Order in Case No. U-21389 required the following:

"If cost recovery for work on the Hardy Dam is sought in its next general electric rate case, Consumers Energy Company shall file a full evaluation of all alternative options and pricing for the work that must be done in order to remain in compliance with Federal Energy Regulatory Commission standards, with projected total costs."

As reflected in Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, line 27, the Company intends to invest \$53.854 million in the Hardy Dam Auxiliary Spillway Project in the projected test year with construction beginning in the fall of 2025. Company witness Monroe is supporting the full evaluation of the alternative options for the Hardy Dam in order to remain in Compliance with FERC requirements and its operating license.

Q. What is the status of the requirements included in the Settlement Agreement in the Company's 2022 Electric Rate Case (Case No. U-21224) for the Muskegon River?

A. The Company has fulfilled the requirements reflected in the Settlement Agreement in the Company's 2022 Electric Rate Case (Case No. U-21224). The Settlement Agreement reached in Case No. U-21224 required the Company to "work with Staff and the Attorney General to scope and conduct the following analyses of all reasonable options prior to commencing construction of the Hardy Dam upgrades:

"a. Economic business cases performed by an outside engineering firm with experience in dam engineering, construction, and decommissioning, that will compare the

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1 projected capital and O&M costs through the end of Hardy
2 Dam's current Federal Energy Regulatory Commission
3 ("FERC") license term, with the value of the energy and
4 capacity that Hardy Dam will provide customers, under a
5 variety of reasonable assumptions. These assumptions will
6 be inclusive of at least the current long-term forecast for
7 energy prices and replacement capacity priced at a range of
8 percentages of the Cost of New Entry. The business case
9 shall utilize best available assumptions and consider, at a
10 minimum, the feasibility and impacts of (i) divestiture, (ii)
11 permanently lowering the reservoir height, (iii) full
12 decommissioning and removal, and (iv) other options that
13 avoid or minimize the impact of the Hardy Dam on customer
14 rates. In addition, the Company will perform, or cause to be
15 performed, an economic assessment of the impact of each of
16 these scenarios on the Muskegon River Hydroelectric Dam
17 communities.

18 b. The Company shall engage in discussions with affected
19 local communities on the costs and timing of the proposed
20 Muskegon River Hydroelectric Dam projects, the need for
21 additional funding from those Muskegon River
22 Hydroelectric Dam impacted communities and possible
23 mechanisms for funding to ensure FERC compliance and
24 dam safety at the Hardy Dam, and the impact to the Hardy
25 Dam and reservoir (as well as the Rogers and Croton dams
26 and reservoirs) if this additional funding is not already
27 recovered in Consumers Energy rates or received from other
28 sources. Prior to construction of the Hardy Dam upgrades,
29 the Company agrees to report on these discussions and
30 inform the Commission whether additional funding from the
31 communities or other sources is feasible (both as to amounts
32 and timing) and provide a best-efforts estimate of the total
33 revenue, if any, that could potentially be available from such
34 sources."

35 **Q. What is the status of the Company's progress on the business cases?**

36 A. Consistent with the terms of the Settlement Agreement, the Company has commissioned
37 the performance of business cases for the Muskegon River Hydro facilities (Croton, Hardy
38 and Rogers) by an outside engineering firm that has experience in dam engineering,
39 construction, and decommissioning. The business cases utilized best available assumptions

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1 and considered divestiture (as will be discussed later in this direct testimony), full
2 decommissioning and removal utilizing all three decommissioning options, and a
3 permanent lowering of the reservoir height. **Confidential** Exhibit A-149 (AJM-7) includes
4 the results of the business cases for the Muskegon River Hydro facilities.

5 In addition, the Company commissioned the performance of an economic
6 assessment of the impact of each of these scenarios on the Muskegon River Hydro facilities
7 communities. The results of these economic assessments are presented in Exhibit A-44
8 (RTB-5).

9 **Q. Did the Company engage the MPSC Staff and the Attorney General in the**
10 **development of the business cases and the economic assessments?**

11 A. Yes. The Company met regularly with the MPSC Staff and the Attorney General to review
12 the scope and receive input on both the business cases and the economic assessments.
13 Through a non-disclosure agreement (“NDA”), the Company shared all relevant
14 information related to each of the scope items, met to both present and discuss the inputs,
15 scope, and results of each of the analyses. The Company provided formal responses to
16 interrogatories regarding the process, data, and the results, facilitated a tour of Hardy Dam
17 for the Attorney General, and also facilitated specific discussions on topics such as
18 probable maximum flood (“PMF”) to ensure understanding of the Hardy project design
19 was as complete as possible.

20 **Q. What is the status of the RFP for River Hydro divestiture?**

21 A. The Company launched an RFP to identify potential buyers for its 13 River Hydro facilities
22 on February 15, 2024. The RFP participants will move through a two-stage evaluation and
23 bidding process that is expected to be complete by the end of 2024.

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1 **Q. Has the Company received responses from the February 15, 2024 RFP?**

2 A. Yes. As part of the first phase of the RFP, which involves bidder screening based on,
3 among other things, qualifications and indicative pricing, the Company received responses
4 to the RFP on March 15, 2024. The Company has evaluated the bids and moved to the
5 second phase of the RFP in April of 2024.

6 **Q. What is the scope of Phase 2 of the RFP process?**

7 A. Phase 2 involves engaging with seven selected entities in due diligence, negotiations, and
8 potential sale agreement(s). Due diligence will be completed during the summer, and
9 negotiations will take place for the remainder of the year.

10 **Q. What is the status of the Company's discussions with affected local communities and**
11 **their ability to provide funding to maintain the River Hydros?**

12 A. To identify the potential for community funding, the Company met with local elected
13 officials and other key community stakeholders (chamber of commerce, economic
14 development, homeowners associations, parks department, etc.) at each River Hydro
15 facility. The Company met several times with each community, the first meeting was to
16 introduce the concept of community funding to the community and gauge their interest and
17 initial thoughts on capacity. If favorable, we asked them to spend some time researching
18 the initial options we discussed to better understand their potential capacity for funding.

19 The Company revisited each community four-to-six weeks later to discuss those
20 options and truly understand the community's capacity to support its operations. At the
21 second meeting the Company did not ask for any commitments. As a result of the meetings,
22 the Company did identify some funding in most communities, but the available funding

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1 was not significant when compared to the Company's current gap between relicensing and
2 decommissioning cost estimates.

3 **Q. What are your thoughts regarding the Company's compliance with the requirements**
4 **of the Settlement Agreement?**

5 A. As a result of the Company's collaboration with the MPSC Staff and the Attorney General,
6 its commissioning of business cases and economic impact studies, and its economic
7 outreach and identification of external funding, it is my opinion that the Company has
8 satisfied the requirements of the Settlement Agreement.

9 **Q. Has the MPSC imposed additional requirements on the Company before moving**
10 **forward with construction on the Hardy Dam?**

11 A. Yes. The March 1, 2024 Order in the Company's 2023 Electric Rate Case (Case No.
12 U-21389) included the following requirement in ordering paragraph D:

13 "If cost recovery for work on the Hardy Dam is sought in its
14 next general electric rate case, Consumers Energy Company
15 shall file a full evaluation of all alternative options and
16 pricing for the work that must be done in order to remain in
17 compliance with Federal Energy Regulatory Commission
18 standards, with projected total costs."

19 Company witness Monroe addresses this requirement in his direct testimony as the
20 Company has included projected project costs for work on the Hardy Dam in this
21 proceeding.

22 **Q. Please describe the Company's anticipated timeline for deciding whether each River**
23 **Hydro will be relicensed, sold, or decommissioned.**

24 A. The Company intends to make a decision on the divestiture of the River Hydros by the end
25 of 2024. Should the Company make a decision to not divest the assets, the Company

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1 would revisit the decision to relicense or decommission the River Hydros, with the
2 intention of making a decision in the 1st quarter of 2025.

3 **Q. Will the Company's decision affect the need for the River Hydro investments and**
4 **expenses requested in this case?**

5 A. No. Regardless of the ultimate decision on whether to relicense, sell, or decommission the
6 respective River Hydro facilities, the investments and expenses requested in this case are
7 needed to appropriately maintain those facilities in order to ensure they are safe and legally
8 compliant. The required diligence which needs to be undertaken in order to make a decision
9 on the future of the River Hydros (e.g., adequate evaluation of the bids submitted by the
10 seven entities which are part of Phase 2 of the RFP process and analysis of the community
11 impact study) means that a decision on the future of the River Hydros cannot be reasonably
12 made until late 2024 at the earliest. Subsequent activities to implement the decision(s) will
13 extend into and beyond the test year for this case. The River Hydro investments and
14 expenses requested in this case are needed to reasonably operate those facilities regardless
15 of the ultimate decision on whether to relicense, decommission, or sell one or more of
16 them.

17 **Q. Would it be reasonable to delay approval of the River Hydro investments and**
18 **expenses requested in this case?**

19 A. No, it would not. Delaying approval of the River Hydro cost recovery in this case would
20 mean denying the Company's ability to execute the investments and operations and

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1 maintenance activities necessary to keep the River Hydro facilities safe and compliant with
2 FERC regulations.

3 **Q. Please provide an overview of the generation asset strategy for Ludington.**

4 A. The strategic plan for Ludington is predicated on retiring the units by July 30, 2069. The
5 Ludington units recently underwent a major overhaul that was intended to provide
6 increased capacity and generation, increased efficiency, reduced maintenance, and an
7 extended service life which supported the 50-year FERC license extension granted in 2019.
8 Ludington is a FERC-regulated hydroelectric facility for which dam safety investments are
9 identified and initiated as a result of regulatory compliance and adherence to FERC
10 processes, including the FERC Part 12 process discussed in Mr. Monroe's direct testimony.

11 **Q. How will the Company's generation asset strategy for Ludington impact its projected**
12 **performance?**

13 A. Based upon the Ludington capital and major maintenance projects that I will discuss later
14 in this direct testimony, the Company's generation asset strategy is expected to result in an
15 ROR of 3.50% for the Ludington units in the test year, as shown on Exhibit A-42 (RTB-2),
16 lines 6 through 11, column (c). During the five-year historical period from 2019 through
17 2023, the Ludington units had average ROR values ranging from 4.94% to 7.75%, as
18 shown on Exhibit A-42 (RTB-2), lines 6 through 11, column (b).

19 **Q. How do the Ludington Units factor into the Company's future renewable energy**
20 **strategy as outlined in the IRP?**

21 A. Given the intermittent nature of solar and wind generation and the Company's plans to
22 move to a zero net carbon future, Ludington is becoming a more critical component of the
23 Company's generation portfolio since it can deliver a significant amount of energy in a

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1 short time period; providing energy supply from the reservoir during periods when the
2 wind doesn't blow and/or the sun doesn't shine. Additionally, when there is an
3 over-abundance of wind and/or solar generation, Ludington can utilize the excess energy
4 to fill the reservoir. Ludington's large energy storage capability greatly enables the
5 transition to renewable energy. However, defective and non-confirming work performed
6 by Toshiba during recent overhaul efforts must be resolved to ensure Ludington can fully
7 provide these intended benefits over its remaining life.

8 **Q. How is this strategy reflected in the Projected Availability for Ludington in the test**
9 **year?**

10 A. The Projected Availabilities for all of the Ludington units in the projected test year ranges
11 from 74.03% to 88.30%, as shown on Exhibit A-42 (RTB-2), lines 6 through 11,
12 column (e). The Projected Availabilities for the Ludington generating units reflect a
13 projected ROR of 3.50% and PFs ranging from 8.49% to 23.29%, as shown on Exhibit
14 A-42 (RTB-2), lines 6 through 11, columns (c) and (d). There are currently no major
15 outages planned for the Ludington units in the test year; shorter outages on all six
16 Ludington units are scheduled throughout the test period, primarily in the spring and fall.
17 These outages will be used, in part, to evaluate and monitor ongoing issues with the
18 Toshiba work. The outages are scheduled during periods in which the likelihood of
19 Ludington unit dispatch is lower, thereby reducing the impact of the outages on customers.

20 **Q. Please provide an overview of the generation asset strategy for the Renewable Energy**
21 **Assets.**

22 A. The Company's strategic plan for Renewable Energy Assets, both wind and solar, has been
23 entirely driven by the Company's MPSC-approved 2021 IRP Settlement Agreement.

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1 Consistent with the IRP, the strategy for the wind assets is to complete construction and
2 have all wind assets in service in 2024 with the completion of Heartland Wind Farm. With
3 respect to solar, the Company plans to continue to add incremental solar resources in
4 accordance with its Clean Energy Plan and Renewable Energy Plan. These solar resources
5 are being added pursuant to the Company's 2018 IRP and 2021 IRP annual solicitations,
6 as discussed in more detail later in this direct testimony. In addition, the Company
7 anticipates that it will also add up to 1,000 MW of wind and solar assets through 2027¹ in
8 support of the Company's Voluntary Green Pricing Program, and their costs will be
9 reconciled through the Company's Renewable Energy Plan. The overall investment
10 objective for the Company-owned assets is to provide funding for projects as appropriate
11 to maintain economic dispatch and capacity from the customer's perspective. The
12 Company has a time-based availability target of 97% for its renewable energy wind assets.
13 This availability target considers those periods during which the wind is sufficient to
14 produce energy. The capital expenditures and major maintenance expenses in the plan are
15 targeted to maintain the designed performance level.

16 **Q. How will the enactment of PA 235 of 2023 impact the Company's renewable energy**
17 **portfolio?**

18 A. As previously discussed in this direct testimony, the Company will be filing a Renewable
19 Energy Plan Amendment no later than November 15, 2024. PA 235 of 2023 has
20 established both renewable and clean energy targets for the future beginning with a
21 renewable energy compliance target of 50% in 2030. The newly passed law became

¹ The Settlement Agreement in the Company's 2021 Renewable Energy Plan Amendment, Case No. U-20984, reflected the addition of up to 500 MW of solar and 500 MW of wind over the period from 2024 through 2027 to support the Company's Large Customer Renewable Energy Program.

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effective on February 27, 2024 and provides for the utilization of renewable energy assets from anywhere within the MISO footprint.

Q. How do the Company's renewable assets translate into customer value?

A. Similar to the Company's River Hydro units, the production cost of the Company's renewable energy assets is zero. As such, all energy sold into the MISO energy market has value provided that the MISO locational marginal prices are positive. Additionally, renewable assets provide the Company's customers with renewable energy credits. As reflected on Exhibit A-42 (RTB-2), lines 20 through 21, column (f), during the five-year historical period from 2019 through 2023, the Cross Winds Energy Park and the Lake Winds Energy Park provided a total NEV of \$166.7 million. The 2023 NEVs for Cross Winds Energy Park and Lake Winds Energy Park were \$18.6 million and \$7.0 million, respectively. As reflected on Exhibit A-42 (RTB-2), lines 22 through 23, column (f), during the two-year historical period from 2022 through 2023, Gratiot Farms Wind and Crescent Wind were provided total NEV of \$68.5 million. The 2023 NEVs for Gratiot Farms Wind and Crescent Wind were \$9.7 million and \$10.7 million, respectively. Heartland Farms Wind Park began commercial operation on January 2, 2024, and as reflected on Exhibit A-42 (RTB-2), line 24, column (f), generated \$0.4 million in NEV in 2023 following its December 29, 2023 commercial operation date. The Company began to measure the NEV for its solar assets in 2020 and the 2020 through 2023 NEV for its Solar Garden Assets totaled \$1,140,655.

Q. Please quantify the capacity value for renewable energy assets.

A. As reflected in Table 2, the renewable asset capacity value based upon the settlement price for Zone 7 in the 2023-2024 PRA is \$0.8 million and the renewable asset hypothetical

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capacity value based upon 75% of CONE for Zone 7 in the 2023-2024 PRA is \$11.2 million.

Q. Why have you included a hypothetical capacity value for each of the generating units or category of generating units?

A. I have included these hypothetical values to reflect the capacity values that the Company uses in its capacity planning process. Company witness Metz provides additional information regarding the capacity value of the Company's generation assets in MISO's PRA as well as the projected capacity margin in future years for Zone 7.

Q. How will the Company determine the reasonableness and prudence of additional investments in the electric generating fleet?

A. Additional investment in the remaining units over and above those necessary to maintain safety and regulatory compliance would require some level of economic benefit for customers, otherwise the investment does not make sense. The generating unit periodic outage plans, projected RORs and, ultimately, projected availability for each generating unit or category of generating units reflects the Company's generation asset strategy.

SECTION II
ENVIRONMENTAL REGULATIONS
OVERVIEW

Q. Can you please list the environmental regulations with which Consumers Energy is required to comply and that are relevant to expenditures for which the Company is seeking recovery in this case?

A. Yes. The Company's fossil-fueled Electric Generating Units ("EGUs") are subject to numerous complex and overlapping air, water, and waste regulations.

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Current (On-going) Environmental Compliance

Environmental Regulations – Air Quality

Q. Describe Consumers Energy’s Existing Air Quality Compliance Strategy (“AQCS”).

A. Over the past decade, Consumers Energy has had expenditures to comply with a variety of air quality-related regulations, including the Cross State Air Pollution Rule, the Mercury and Air Toxics Standards, and the Michigan Mercury Rule, among others. The background and purpose of each such rule has been discussed in the testimony of prior rate cases, including Case No. U-17735. To comply with these regulations, Consumers Energy created the AQCS. Cost recovery reflecting the Company’s AQCS was approved in the November 19, 2015 Order in the Company’s 2014 Electric Rate Case (Case No. U-17735). This AQCS has prudently ensured compliance with applicable state and federal air-quality related regulations. The Company’s actions and investments to achieve such compliance have been performed in a manner which has minimized, to the extent reasonably possible, the associated costs for customers. The investments made to ensure environmental compliance have allowed the continued operation of coal generation while the Company transitions to carbon-free generation sources like solar.

Q. Are there any updates to the air quality-related regulations for which the Company’s existing AQCS complies?

A. Yes. In April 2022 the Environmental Protection Agency (“EPA”) proposed the “Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard.” The EPA’s rule was finalized, effective March 15, 2023. The rule resulted in very little impact to the Company in the short term. The rule does contain a budget re-allocation provision which will ratchet down the nitrogen oxide

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1 (“NOx”) allowances allocated to the Company, so the Company will continue to monitor
2 the rule and evaluate the various options for compliance.

3 **Q. What are the capital investments and/or O&M expenses the Company is seeking**
4 **recovery of in this case that are specifically related to air quality control?**

5 A. Any capital and/or O&M required for the operation of the air quality control systems that
6 the Company is seeking recovery can be found in Exhibits A-12 (RTB-3), Schedule B-5.2
7 and A-43 (RTB-4).

8 **Q. Are you seeking recovery of any expenses related to the regulation of greenhouse**
9 **gases from EGUs?**

10 A. No, not at this time. The EPA released proposed greenhouse gas (“GHG”) regulations for
11 power plants under Section 111 of the Clean Air Act in May 2023. The proposed
12 regulation covered GHG emissions from existing coal-fired and some existing natural
13 gas-fired units. The rule does not impact the Company’s remaining coal-fired units due to
14 the May 2025 retirement date for all coal-fired units. The EPA announced in March 2024
15 that when the proposed Section 111 rule is finalized, scheduled for April 2024, it will no
16 longer cover existing natural-gas fired units. EPA states that existing natural-gas fired
17 units will be covered in a future regulation.

18 **Environmental Regulations and Compliance Strategy – Waste**

19 **Q. Can you please describe the relevant parts of the Resource Conservation and**
20 **Recovery Act (“RCRA”) as related to Coal Combustion Residuals (“CCR”)**
21 **management?**

22 A. On April 17, 2015, the EPA published 40 CFR Parts 257 and 261, Disposal of CCRs from
23 Electric Utilities, in the Federal Register under Subtitle D of the RCRA. The rules establish

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1 minimum national criteria for purposes of determining which CCR solid waste disposal
2 facilities and solid waste management practices pose a reasonable probability of adverse
3 effect on health or the environment under RCRA. The rule is considered
4 self-implementing, meaning that affected facilities must certify compliance with the
5 published standards and schedules. By codifying standards under Subtitle D, Owners and
6 Operators are not required to obtain permits, and states are not required to adopt and
7 implement the new rules. Instead, the rules' only enforcement mechanism is for a state or
8 citizen group to bring a RCRA citizen suit in federal district court against any facility that
9 is alleged to be in noncompliance with the newly promulgated minimum standards. In
10 December 2016, the Water Infrastructure Improvements for the Nation ("WIIN") Act was
11 passed. This bill provides authority for state implementation of coal ash management
12 through a state permit program in lieu of the current enforcement of the CCR Rule through
13 the RCRA citizen-suit authority. States may elect to submit a CCR permit program to the
14 EPA for approval. The State of Michigan revised its solid waste statute in late 2018 to
15 outline a state CCR permitting program. Michigan has submitted its application to the EPA
16 for a permit program and is awaiting the EPAs review of administrative completeness. In
17 the interim, the EPA has enforcement authority over the RCRA-CCR Rule as provided in
18 the WIIN Act.

19 The existence of a state permitting program allows Department of Environment,
20 Great Lakes, and Energy ("EGLE") to issue permits under Michigan's solid waste
21 management statute (Part 115 of the Natural Resources and Protection Act of 1994
22 ("NREPA"), as amended) to regulate compliance schedules and activities for CCR landfills
23 and surface impoundments. Although the current state CCR permitting program was

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1 passed into law and Consumers Energy is obligated to comply with the associated statute,
2 permits, and licenses, the program must be approved by the EPA on the basis that it is “as
3 protective as” the CCR Rule to avoid dual state and federal regulation. Thus, similar
4 compliance standards are required within the state permitting program, including
5 requirements to make compliance documentation publicly available, completing the work,
6 and then self-reporting by providing notifications to EGLE and posting to a publicly
7 accessible compliance website.

8 **Q. What are the capital and/or O&M investments Consumers Energy is seeking**
9 **recovery of in this case that are specifically related to RCRA compliance and/or**
10 **overall CCR Management?**

11 A. The Company’s CCR management compliance strategy was approved in Case No.
12 U-18322. The major capital work for compliance has been completed. The Cost of
13 Removal (“COR”) and/or O&M required for the management of CCRs under the RCRA
14 that the Company is seeking recovery of can be found in Exhibits A-122 (JJK-3) and A-42
15 (RTB-4). The COR expenses represent historical expenses only. Separately, there are
16 closure activities that will continue throughout the bridge period and test year and beyond;
17 however, those expenses are COR and are not included in this filing.

18 **SECTION III**
19 **GENERATION CAPITAL EXPENDITURES**
20 **OVERVIEW**

21 **Q. What factors does the Company consider in determining the capital investments that**
22 **it will make at its generating plants?**

23 A. The major drivers in the determination of generation capital investments are plant safety,
24 compliance with regulations, and reliability. Consumers Energy’s strategy for complying
25 with environmental regulations was previously discussed in this direct testimony.

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1 **Q. Please describe Exhibit A-12 (RTB-3), Schedule B-5.2, Generation Capital**
2 **Expenditures.**

3 A. This exhibit presents the capital expenditures for Generation, 2023 through the projected
4 test year - 12 months ending February 28, 2026. Exhibit A-12 (RTB-3), Schedule B-5.2,
5 is a nine-page exhibit. Page 1 of this exhibit presents a summary of Generation capital
6 expenditures for the Historical Period ended December 31, 2023, the Projected 14-month
7 Bridge Period beginning January 1, 2024 and ending February 28, 2025, and the projected
8 test year beginning March 1, 2025 and ending February 28, 2026. This summary
9 information is broken down by Steam Power Generation, Hydraulic Power Generation,
10 Pumped Storage Generation, and Other Production Plant. Pages 2 through 5 of this exhibit
11 capture the same Historical Year, Bridge Period, and Test Year Generation capital
12 expenditures information, but is presented by generating sites and environmental
13 categories. This information is further detailed by Contractor, Labor, Materials, Business
14 Expenses, Contingency, and Other. Page 6 of this exhibit represents a summary of pages 2
15 through 5 of this exhibit. Finally, pages 7 through 9 of this exhibit identify the capital
16 projects and associated expenditures that are greater than \$1 million that contribute to the
17 overall capital expenditures summarized on pages 1 through 6 of this exhibit. Specifically,
18 page 7 of this exhibit presents capital projects for the Historical Period ended December 31,
19 2023; page 8 of this exhibit presents capital projects for the Projected 14-month Bridge
20 Period beginning January 1, 2024 and ending February 28, 2025; and page 9 of this exhibit
21 presents capital projects for the projected test year ending February 28, 2026.

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1 **Q. What project information is presented on Exhibit A-12 (RTB-3), Schedule B-5.2,**
2 **pages 7 through 9?**

3 A. Exhibit A-12 (RTB-3), Schedule B-5.2, pages 7 through 9, presents the generation type,
4 the generation unit, project type, project classification, project description, and project cost
5 information. The project type identifies whether the project is routine or non-routine.
6 Routine projects include work that is performed regularly; whereas, non-routine projects
7 are typically undertaken once every 10 years or longer. The budget approval reflects the
8 status of internal approval for the project, including projected cost amount. Exhibit A-12
9 (RTB-3), Schedule B-5.2, page 7, includes both projected and actual capital project cost;
10 whereas, Exhibit A-12 (RTB-3), Schedule B-5.2, pages 8 and 9, includes only the project
11 projected amount.

12 **Q. What level of capital spending for generating plants does the Company request the**
13 **Commission to incorporate into rates in this case?**

14 A. The Company's rate relief request in this case reflects capital spending on projects for its
15 generating plants of \$859.095 million for the historical test year ended December 31, 2023
16 as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 1, line 17, column (b);
17 \$463.548 million in the projected 14-month Bridge Period ending February 28, 2025 as
18 shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 1, line 17, column (e); and
19 \$600.484 million in the projected test year ending February 28, 2026 as shown on Exhibit
20 A-12 (RTB-3), Schedule B-5.2, page 1, line 17, column (f).

21 **Q. Has the Company included any contingency in the requested capital expenditures for**
22 **Generation?**

23 A. No. The Company no longer includes contingency in its generation projects.

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1 **Q. Please explain how the Company prioritizes its capital investments within**
2 **Generation.**

3 A. In evaluating capital investments, the Company's first priority is addressing safety,
4 regulatory, compliance, and continued operation related projects. These projects are
5 considered a mandatory cost of doing business. Safety, regulatory, compliance, and
6 continued operation-related projects provide economic value to customers in that they
7 allow the units to remain in service and avoid potential derates and/or shutdown due to an
8 intervention by various regulators including Occupational Safety and Health
9 Administration ("OSHA"), EGLE, the EPA, and FERC. In order to minimize the impact
10 of these projects on customers, the Company utilizes a least cost/best fit ("LCBF") analysis
11 for the investments necessary to satisfy service quality, safety, and Federal and State policy
12 requirements.

13 **Q. How does the Company determine whether other projects get approved for funding?**

14 A. In accordance with the Company's generation asset strategy for each generating unit or
15 category of generating units, economic projects that are expected to reduce ROR,
16 maintenance cost or heat rate, all else being equal, are evaluated to ensure that their
17 implementation results in a net benefit to the customer. For a project to receive approval
18 for implementation, the projected benefits of the work must have a greater value than the
19 cost of implementing the project. In other words, the implementation of the project should,
20 at a minimum, result in a marginal customer benefit.

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1 **Q. How does the Company evaluate other capital investments, such as economic**
2 **projects?**

3 A. The Company uses two financial measures, Internal Rate of Return (“IRR”) and Present
4 Value Ratio (“PVR”), as a means to evaluate and prioritize projected economic projects
5 within Generation. A complex financial model was developed in-house that allows the
6 Company to calculate and measure the numerous changes that result when improvements
7 (both O&M and Capital) are made to its rate-based generating units.

8 **Q. Does the Company calculate IRRs or PVRs for all projects?**

9 A. No. The Company calculates IRRs or PVRs for economic projects that are not considered
10 required but would yield net benefits to customers. Projects required for regulatory,
11 compliance, and/or continued operations are reviewed to assure that the project is cost
12 effective and result from a reasonable evaluation of alternatives, but because the project
13 must be done for compliance and continued operation, IRR or PVR may not be calculated.
14 When evaluating project alternatives related to regulatory, compliance, and/or continued
15 operations, IRRs or PVRs may be used to rank alternatives.

16 **Q. Please explain what you mean by projects for continued operations.**

17 A. Projects for continued operations refers to projects which are necessary to allow the
18 generating unit to continue to operate through its retirement date. Alternatives for projects
19 necessary for continued operation will generally be evaluated based upon LCBF. For this
20 evaluation, one of the alternatives will include a decision to not perform the project and
21 either retire the unit earlier than projected or operate the unit at a permanent derate.

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1 **Q. How does the Company evaluate customer benefits associated with**
2 **generation-related capital investments?**

3 A. The Company uses replacement power cost estimates and PSCR impacts when evaluating
4 customer benefits. The Company also evaluates ROR and heat rate improvements, which
5 result in increased and/or lower cost generation.

6 **Q. How does the Company evaluate historical events which have impacted availability?**

7 A. The cause of each of the historical events impacting availability are evaluated and
8 measured, and the actions necessary to avoid the same or similar events are considered for
9 implementation. In many cases, actions necessary to prevent the event from recurring are
10 cost beneficial. The availability projections, including ROR, simply reflect the Company's
11 best estimate of the operational benefits of those corrective actions that have already been
12 taken or are planned to be taken, through the projected test year ending February 28, 2026.

13 **Q. Does the Company evaluate customer benefits associated with Outage Schedules?**

14 A. Yes, the Company uses historical market prices to evaluate timing around outages in an
15 effort to ensure the unit is available during periods in which market pricing is projected to
16 be high.

17 **Q. Is it possible that the Company could experience changes to its scheduled outages and**
18 **forecasted capital expenditures in the future?**

19 A. Yes. The Company often forecasts future actions and capital expenditures based on
20 currently available information, many months before the work is completed. To provide
21 some perspective, the outage schedule used in this case was approved in August 2023.
22 A review of the outage schedule used in this case identifies eight scheduled outages that
23 begin in March 2025 (18 months after the schedule was approved) and run through

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1 February 28, 2026, 29 months later. During each of these eight scheduled outages,
2 Consumers Energy has scheduled a number of tasks to be performed. Because of the long
3 lead times, the number of outages scheduled during the test year, and the fact that several
4 different tasks will be performed during each outage, it is inevitable that some scheduled
5 outages and forecast capital expenditures will change. However, the Company has a
6 history of prudent capital investments in its generating facilities, which have been
7 consistently supported by the Commission.

8 **Q. Are there other reasons why outage schedule changes occur?**

9 A. Yes. Some of the reasons why outage schedule changes occur are: contractor availability,
10 parts availability, changes in regulations, design changes, outage scope changes, changes
11 in unit condition, and spot market prices.

12 **Q. Can you provide an example of when circumstances changed?**

13 A. Yes. The Company's fall 2023 outage for Campbell Unit 1 was originally scheduled from
14 October 13, 2023 through November 12, 2023. The unit was placed into economic reserve
15 status on February 19, 2023 and subsequently began a maintenance outage on March 7,
16 2023. The maintenance outage lasted for 14 days, ending on March 21, 2023. During this
17 timeframe, all priority work scope that was scheduled for the fall outage was completed,
18 obviating the need for the planned outage scheduled to begin on October 13, 2023.

19 **Q. Please describe how the Company determines its generation projected capital**
20 **expenditure amounts.**

21 A. Consistent with the Company's generation asset strategy, generation projected capital
22 investments support the continued safe, regulatory compliant, and reliable operations of
23 the Company's electric generating fleet. Projected capital investments are informed by

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1 historical and anticipated performance of the units. The reasonableness of the generation
2 capital investments is indicated by the sustained or improved performance of the
3 Company's electric generating fleet relative to: (1) the safety of the employees, contractors,
4 and community at and around the generating facilities; (2) compliance with rules and
5 regulations; and (3) reliably participating in the energy, resource adequacy, and ancillary
6 services markets.

7 **Q. How are projects identified that are discussed later in this direct testimony?**

8 A. Generation System Planners assess the equipment performance and compare that
9 assessment with the generation asset strategy for the generating unit. Upon identification
10 of a potential project, the Planner will complete a project initiation document ("PID"). This
11 document defines the issue, alternatives considered for resolution, intended benefits or
12 consequences avoided, and suggested timing and a cost estimate. The document is
13 reviewed by multiple groups for alignment and ultimately routed for approval for inclusion
14 in the Long-Term Financial Plan ("LTFP"). PIDs entered into the LTFP will typically be
15 scheduled three to five years in the future to align with outages and provide the project
16 execution teams ample time to plan and engineer.

17 **Q. How were the projected capital expenditure amounts developed for each of the**
18 **projects discussed later in this direct testimony?**

19 A. Each project begins with the creation of a PID. The Planner will provide an initial cost
20 estimate for the project within the PID. The Planner utilizes past experience, contractor
21 cost estimates, internal estimates, Original Equipment Manufacturer ("OEM") data, and
22 studies to provide the best estimate of the costs. This activity typically takes place three to
23 five years prior to the start of project execution.

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1 **Q. How are PIDs related to Concept Approval Documents (“CADs”)?**

2 A. The PID is the mechanism utilized to allow projects to be considered for the LTFP. Once
3 the project is included in the LTFP and the project is within a year of start of execution,
4 the CAD is created. The CAD is templated from the PID and updated as necessary. The
5 CAD is then routed for approval to the designated level of management based on project
6 amount and, once approved, the project will be initiated.

7 **Q. Do adjustments to the projected capital investment amounts for each of the projects**
8 **occur prior to project implementation?**

9 A. Yes. As the project team progresses through the life cycle of a project, there are multiple
10 opportunities to better define project costs. Activities such as detailed engineering,
11 bidding, contractor involvement, and construction all allow for budgets to be better defined.
12 As this definition evolves, the projected capital investments are updated accordingly.

13 **2023 HISTORICAL TEST YEAR CAPITAL EXPENDITURES**

14 **Q. How does the 2023 actual capital expenditure amount of \$859.095 million compare to**
15 **the amount of capital expenditures reflected in the Company’s request in Case No.**
16 **U-21389?**

17 A. The 2023 actual capital expenditure amount of \$859.095 million is \$430.277 million below
18 the Company’s requested amount in Case No. U-21389. The reduction in the Company’s
19 actual capital expenditure amount is directly attributable to the removal of the capital
20 expenditures for IRP solar projects and the actual accounting treatment of the Covert
21 purchase. While the Covert total purchase cost was consistent with projections, the total
22 amount was not recorded as an addition to plant in service. The actual amount recorded as
23 capital was \$151.858 million less than the projected purchase amount as can be seen on

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1 Exhibit A-12 (RTB-3), Schedule B-5.2, page 7, line 3, columns (g) and (h). The projected
2 amounts for the 2019 and 2020 IRP Solar Bid Events totaled \$355.250 million in the
3 Company's 2023 Electric Rate Case No. U-21389 (see Exhibit A-12 (RTB-3), Schedule
4 B-5.1, page 9, lines 38 and 39, column (n)), however these amounts were removed from
5 the case due to their project status. The projected solar project capital expenditures were
6 not projected to close by the end of the projected test year and were offset by the allowance
7 for funds used during construction ("AFUDC"). As such, the underspend did not impact
8 the revenue requirement. A compilation of the 2023 projects which have actual capital
9 expenditure amounts greater than \$1 million is presented on Exhibit A-12 (RTB-3),
10 Schedule B-5.2, page 7.

11 **Q. How does the compilation of capital projects on Exhibit A-12 (RTB-3), Schedule**
12 **B-5.2, page 7, compare with the 2023 capital projects reflected on Case No. U-21389,**
13 **Exhibit A-12 (RTB-3), Schedule B-5.1, page 9?**

14 A. A comparison of the projects on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7, with the
15 2023 projects reflected on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1,
16 page 9, reveals that there are seven projects on Exhibit A-12 (RTB-3), Schedule B-5.2,
17 page 7, which were not reflected on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule
18 B-5.1, page 9. In addition, there were twenty projects for 2023 that were reflected on Case
19 No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, that are not presented on
20 Exhibit A-12 (RTB-3), Schedule B-5.2, page 7.

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Q. Please discuss the 2023 capital projects that were included on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, that are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7.

A. The following projects are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7, due to the fact that their actual 2023 capital expenditure amount was less than \$1 million, the project was disallowed, reduced in cost, or not pursued in 2023. The disposition of these capital projects is provided below:

Below is a list of projects whose projected bridge period costs were disallowed in the final order in Case No. U-21389:

Project Description	Projected Amount
Covert Non LTSA Capital - Extras not included in contract	\$ 3,942,510
Karn Tank Farm Storage Tank Heating Line Replacement	\$ 1,253,971
Karn Sync Wire Replacement	\$ 1,450,000
Alcona Core Wall Remediation Project	\$ 1,810,370
Rogers Probable Maximum Flood Project	\$ 1,898,708
2019 Solar Bid Event – Mustang Mile	\$ 233,064,275
2020 Solar Bid Event – Washtenaw	\$ 122,186,164

Below is a list of projects whose projected bridge period costs were reduced or deferred by the Company and their projected amounts approved in the final order in Case No. U-21389 were less than \$1 million:

Project Description	Projected Amount	Project Reduction
Webber Unit 1 Generator Rewind	\$ 1,020,000	\$ 1,020,000
Zeeland Milestone Outage Capital to GE - Part of LTSA Contra	\$ 7,870,000	\$ 7,870,000
Zeeland Unit 4 Field Rewind of Generator Rotor	\$ 1,205,357	\$ 1,205,357
Zeeland Unit 3 Field Rewind of Generator Rotor	\$ 1,205,357	\$ 1,205,357
Cooke Spillway Hoist Replacement	\$ 2,100,000	\$ 1,492,000
Zeeland Phase 2 599 699 345kV Breaker Replacement	\$ 1,222,915	\$ 773,000
Ludington Oil Water Separator Replacement	\$ 1,162,917	\$ 679,000
Ludington Unit 1-6 DCS Control Relay Replacement	\$ 1,347,516	\$ 727,000

Below is a discussion of the remaining million-dollar projects whose actual 2023 capital expenditures were less than projected:

- Zeeland Heat Recovery Steam Generator (“HRSG”) Casing Replacement (\$2,803,333). This project is scheduled to be completed in 2024. The Company

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spent a total of \$699,676 in 2023 and \$2,097,620 is scheduled for the projected bridge period ending February 28, 2025;

- Zeeland Generator Step Up Transformer Replacement (Spare) (\$2,883,33). During 2023, the Company spent a total of \$758,314 on this project, \$589,607 is planned for the bridge period ending February 28, 2025, and \$6.449 million is planned for the test year ending February 28, 2026;
- Five Channels Dead Bay and Log Chute Remediation (\$1,981,666). This project was completed in 2023; however, the project was entirely a removal project. As such, a total of \$2,134,312 was recorded to cost of removal and a negative \$331,235 was recorded to capital;
- Ludington Replace Barrier Net Panels (\$1,088,614). The Company spent a net total of \$705,769 in 2023 as a result of an offset of \$747,499 from the Ludington co-owner; and
- Karn Units 3 and 4 Separation (\$1,789,545). The separation work was performed in 2023; however, a large portion of the expense was recorded to cost of removal. The Company pursued a separate project (Karn Units 3 and 4 boiler plant heating) as an alternative to upgrading the auxiliary boilers as part of the utility separation. I will discuss that project later in this direct testimony.

Q. Please discuss the 2023 capital projects that were not included in Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, that are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7.

A. The disposition of these capital projects is presented below:

- Covert Information Technology (“IT”) Room (\$2,059,520). The scope of this project was to provide the plant connectivity to the Consumers Energy’s SCADA and corporate networks while keeping the plant fully operational during the transition from the legacy network to Consumers Energy networks. The North American Electric Reliability Corporation (“NERC”) Critical Infrastructure Protection (“CIP”) regulation requires that the SCADA and corporate networks be separate from each other and, due to the legacy network needing to remain operational during the transition, IT required a new IT Room to be built to house the corporate network infrastructure;
- Covert Security and Network (\$2,208,169). The scope of this project was to ensure the plant is meeting the physical security requirements for CIP Low assets. Due to the plant having minimal CIP Low physical security assets in place, Consumers Energy’s corporate security team was required to install new cameras and card readers throughout the site where all CIP Low assets reside;

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- 1 • Covert Spare Generator Stepup (“GSU”) Transformer (\$1,722,987). The scope
2 of this project is the procurement of a spare transformer for the Covert
3 Generating Station. The 2023 capital expenditure reflects a milestone payment
4 to the best identified bidder and internal loadings. This project will be discussed
5 in more detail later in this direct testimony;
- 6 • Karn Units 3 and 4 Boiler Plant Heating (\$4,836,052). The Karn Units 3 and
7 4 Plant Heating Boilers Project was a strategic initiative aimed at upgrading the
8 plant heating system at Karn Power Station. The project involved the
9 procurement and installation of two smaller, more efficient boilers for
10 continuous plant heating. Prior to implementing this project, the existing
11 auxiliary boilers were utilized, and the auxiliary boilers were both inefficient
12 and unreliable for continuous plant heating. Originally, the auxiliary boilers
13 were to be used for plant heating and were to be addressed as part of the Karn
14 Units 3 and 4 separation as previously discussed in this direct testimony;
- 15 • Karn Unit 3 Exciter Rewind (\$1,038,719). The scope of this project was to
16 remove the Karn Unit 3 Exciter Rotor and send it out to be rewound. This work
17 was required as a result of the main lead in the exciter rotor failing open. Once
18 the exciter was disassembled at the vendor facility, the broken lead and the
19 resulting inability to excite was identified. To repair the broken main lead, a
20 full rewind was needed because the main lead was buried under the windings;
- 21 • Jackson Multimedia Filtration Pilot Skid (\$2,441,755). The scope of this
22 project was to perform testing and calibration as well as provide system
23 improvements to the treatment systems for the well water. The specific scope
24 of the project includes the installation of larger bleach pumps in order to pump
25 a higher flowrate of bleach to counteract the bleach degradation, replacement
26 of caustic pumps on caustic injection system due to issues with pump
27 performance, replacement of variable frequency drive and breaker damaged by
28 caustic injection system, replacement of control valve on well water forwarding
29 pump to increase the flowrate up to the required 1,150 gpm, adjustment of the
30 logic in the reverse osmosis pretreatment system to remove ability for all
31 (4) beds to backwash at the same time, run various scenarios to optimize the
32 throughput of the greensand filters, the caustic in the pretreatment, and the
33 bleach in the pretreatment, and other system improvement activities;
- 34 • Zeeland Unit 5 GSU Transformer Rewind (\$13,884,854). The scope of this
35 project was to remove the failed Zeeland Unit 5 GSU transformer, movement
36 and installation of the spare GSU transformer, and sending out the failed
37 Zeeland Unit 5 GSU transformer for overhaul which included milestone
38 payments for the overhaul. In addition, the scope reflected the monthly lease
39 of a spare transformer to provided continued operation of the unit for customers.
40 Zeeland Unit 5 was taken out of service on December 17, 2022 and was returned
41 to service on January 23, 2023 upon installation of the leased transformer which
42 was moved from Zeeland Unit 1; and

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- Croton 1 and 2 Wicket Gate (\$4,329,769). This projected was originally expected to be completed in 2022 however during project implementation a significant amount of additional work was identified during project execution.

**PROJECTED 14-MONTH BRIDGE PERIOD CAPITAL
EXPENDITURES**

Q. How does the projected 14-month bridge period capital expenditure of \$464 million compare to the amount of capital approved by the MPSC in Case No. U-21389 for 2024?

A. The 14-month bridge period projected capital expenditure amount of \$463.548 million is \$5 million less than the projected test year amount of \$468.684 million requested in the Company's last electric rate case (Case No. U-21389). The difference between the 14-month bridge amount requested in Case No. U-21389 and the amount requested in this proceeding includes changes in the projects for which recovery is being requested. For example, the inclusion of projected capital expenditures for BESSs is offset by the reduction in projected costs for IRP solar projects. Each of these project areas are discussed in more detail in witness Clark's direct testimony. A compilation of the 14-month bridge period projects which have projected capital expenditure amounts greater than \$1 million is presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8.

Q. How does the compilation of 14-month bridge period capital projects on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, compare with the test year capital projects reflected on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 10?

A. A comparison of the 14-month bridge period capital projects on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, with the test year projects reflected on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 10, reveals that there are 26 projects on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, which were not reflected on Case No. U-21389, Exhibit

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A-12 (RTB-3), Schedule B-5.1, page 8. In addition, there were 17 projects for the 12-month period ending February 28, 2025 that were reflected on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 10, that are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8.

Q. Please discuss the test year capital projects that were included on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 10, that are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8.

A. The following projects are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, due to the fact that the projected bridge period capital expenditure amounts are now less than \$1 million or the project is not being pursued in the bridge period. The disposition of these capital projects is presented in the table below:

Site	Project	Disposition
Alcona	Risk Informed Decision Making Resolution	Disallowed in U-21389 Final Order
Cooke	Head Gate Replacement Project	Reflected in Test Year Investment
Covert	Non Long Term Service Agreement Capital - Extras	Disallowed in U-21389 Final Order
Five Channels	Trash Rack Ergonomics Project	Reflected in Test Year Investment
Foote	Unit 2 Wicket Gates Replacement Project	Project Deferred by Company in U-21389
Foote	ADA Ramp Investigation and replacement	Project Deferred by Company in U-21389
Hardy	Electrical Safety Project	Project Deferred by Company in U-21389
Hardy	Hardy Splash Wall Replacement	Disallowed in U-21389 and moved to test year
Hodenpyl	Downstream Wall	Reflected in Test Year Investment
Jackson	LM 1 - 6 SAC Extended Life Combustor	Project Deferred by Company in U-21389
Ludington	Administrative Building Addition	Project Deferred by Company in U-21389
Ludington	Replace Barrier Net Panels	Staff reduced project spend to \$0.476 million
Ludington	Intake Gate and Gate House Mechanical Replacement	Staff reduced project spend to \$0.700 million
Solar	Solar - 2019 Bid Event (Mustang Mile 150 MW)	Disallowed in U-21389 Final Order
Solar	Solar - 2020 Bid Event (Washtenaw Solar) (150 MW)	Disallowed in U-21389 Final Order
Webber	Unit 1 Generator Rewind	Project Deferred by Company in U-21389
Zeeland	Purchase of Site Spare GSU	Reflected in Test Year Investment

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Q. Please identify the 14-month bridge period capital projects that were not included on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 10, that are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9.

A. The bridge period capital projects that were not included on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 10, are presented in the table below:

Line No.	Project Description
1	Covert Purchase of site spare GSU
2	Covert Cooling Tower Gearboxes
3	Covert SCR/CO Catalyst Replacement - Unit 2
4	Covert SCR/CO Catalyst Replacement - Unit 3
5	Covert 1-3 Emerson DCS Evergreen
6	Jackson GE LTSA Historical Extra Work Expected
7	Zeeland 2C GSU Rewind
8	Zeeland Phase I Gas Turbine Advanced gas path replacement and axial fuel staging
9	Zeeland LTSA - Extras not included in contract (cranes, mobile equipment)
10	Zeeland Long Term Service Agreement - Running Capital Contract
11	Zeeland HRSG Casing Replacement
12	Karn 3 DCS Evergreen
13	Karn 3&4 Sync Wire Replacement
14	Karn 4 Replacement of Ductwork Insulation and Lagging
15	Karn 4 DCS Evergreen
16	LPS - LPEJ Chamber water stop replacement
17	Alcona Artesian Design Study
18	Foote Spillway Hoist Replacement
19	Hardy Auxiliary Spillway Replacement
20	Hodenpyl - Emergency Spillway Project
21	Hodenpyl Spillway Hoist Replacement
22	Tippy - Unit 1 Thrust Bearing Replacement
23	Solar - 2022 Bid Event (Spring Creek)
24	Armstrong BESS (IIJA Grant App)
25	Iosco BESS (IRP)
26	Weadock BESS (IRP)

The basis for projects 1 through 16 will be discussed in more detail later in this direct testimony, the basis for projects 17 through 22 will be discussed in the direct testimony of Company witness Monroe, and the basis for projects 23 through 26 will be discussed in the direct testimony of Company witness Clark.

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1 **Q. Is the projected capital expenditure amount of \$463.548 million for the 14-month**
2 **bridge period ending February 28, 2025, on Exhibit A-12 (RTB-3), Schedule B-5.2,**
3 **page 1, column (e), consistent with the Company's generation asset strategy?**

4 A. Yes. Based upon a review of the projected capital expenditure presentation on Exhibit
5 A-12 (RTB-3), Schedule B-5.2, pages 2 and 3, lines 1 through 99, column (h),
6 \$249.572 million of that capital will fund solar projects pursuant to the Company's IRP,
7 \$39.672 million will fund BESS projects, \$118.854 million of that total capital expenditure
8 amount will be used at the Company's natural gas generating facilities which includes
9 Covert, Jackson, Zeeland, and Karn Units 3 and 4. In addition, \$10.279 million will fund
10 various projects at the LPS facility, and \$42.376 million will fund various hydro safety,
11 reliability, and regulatory compliance projects. With the exception of the solar, BESS, and
12 the River Hydro projects, a detailed discussion of the various projects for each generating
13 unit or group of generating units will be provided later in this direct testimony. The River
14 Hydro projects will be discussed in the direct testimony of Company witness Monroe and
15 the solar projects will be discussed in the direct testimony of Company witness Clark.

16 **PROJECTED TEST YEAR CAPITAL EXPENDITURES**

17 **Q. Is the projected capital expenditure amount of \$600.484 million for the test year**
18 **ending February 28, 2026, on Exhibit A-12 (RTB-3), Schedule B-5.2, page 1,**
19 **column (f), consistent with the Company's generation asset strategy?**

20 A. Yes. Based upon a review of the projected capital expenditure presentation on Exhibit
21 A-12 (RTB-3), Schedule B-5.2, pages 2 and 3, lines 1 through 99, column (j),
22 \$275.959 million of that capital will fund solar projects pursuant to the Company's IRP,
23 \$78.921 million will fund BESS projects, \$134.664 million of that total capital expenditure

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1 amount will be used at the Company's natural gas generating facilities which includes
2 Covert, Jackson, Zeeland, and Karn Units 3 and 4. In addition, \$15.587 million will allow
3 the Company to complete various regulatory, reliability, and infrastructure projects
4 necessary to support the 50-year license extension at Ludington granted by FERC in 2019
5 and \$92.258 million will fund various hydro safety, reliability, and regulatory compliance
6 projects. Except for the solar projects and the River Hydro projects, a detailed discussion
7 of the various projects for each generating unit or group of generating units will be provided
8 later in this direct testimony. The River Hydro projects will be discussed in the direct
9 testimony of Company witness Monroe and the solar projects will be discussed in the direct
10 testimony of Company witness Clark.

11 **Campbell Units 1, 2, and 3**

12 **Q. Please explain the Company's projected capital investment for the 14-month**
13 **projected bridge period ending February 28, 2025 and projected test year ending**
14 **February 28, 2026 for Campbell Units 1, 2, and 3.**

15 **A.** The Company does not plan to invest any capital in the Campbell units during the bridge
16 period or test year, as reflected on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, lines 1
17 and 8. As presented on Exhibit A-43 (RTB-4), lines 1 and 2, and as discussed later in this
18 direct testimony, the Company has projected modest amounts of major maintenance to
19 ensure that these units are able to operate through their retirement date of May 31, 2025.

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Covert Plant

Q. Please explain the Company's projected capital investment for the 14-month projected bridge period ending February 28, 2025 and projected test year ending February 28, 2026 for Covert.

A. The Company plans to invest a total of \$34.087 million in the 14-month bridge period and \$61.483 million in the test year at the Covert Plant. These capital investments will be facilitated by nine-day outages at Covert Units 1 through 3 in the spring and fall of 2025 as well as longer unit outages for major inspections. Covert Unit 1 has a 58-day outage scheduled to begin on February 1, 2026, Covert Unit 3 has a 59-day outage scheduled to begin on November 1, 2025, and Covert Unit 2 has a 58-day outage scheduled to begin on February 1, 2025.

Q. Please explain the Company's projected capital investment for the 14-month bridge period ending February 28, 2025 for the Covert Plant.

A. The Company plans to invest a total of \$34.087 million in the bridge period on the Covert Plant, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 43, column (h).

Q. What is the basis for the projected \$34.087 million capital investment in the 14-month projected bridge period?

A. The projected \$34.087 million capital investment in the projected bridge period will fund numerous projects at the Covert Plant. Six of these projects are greater than \$1 million, and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 1 through 6.

The basis for these six projects is described below:

- Purchase of site spare GSU (1,000,000). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;

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- Cooling Tower Gearboxes (\$1,161,732). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Selective Catalytic Reduction (“SCR”)/Carbon Monoxide (“CO”) Catalyst Replacement - Unit 2 (\$1,041,667). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- SCR/CO Catalyst Replacement - Unit 3 (\$1,041,667). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Covert Units 1 through 3 Emerson Distributed Control System (“DCS”) Evergreen (\$1,041,250). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert; and
- Covert Plant Long-Term Service Agreement (“LTSA”) (\$20,400,000). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert.

The following projects are less than \$1 million, but are important to reliability:

- Covert Plant (Units 1, 2, and 3) LTSA extra work (\$1,748,333 total). The LTSA extra work is defined as the work that is not covered under normal planned maintenance in the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items not covered under the LTSA that need to be addressed are labor and material to replace the following: blading, ammonia delivery system, SCR catalyst, turbine rotors, cooling towers, and turbine cooling air cooler;
- Excitation Replacement (\$340,000). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Office Space Consumers Energy Warehouse with Loading Dock (\$493,333). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Plant Replace Sulfuric Sodium Hypo and Building (\$410,000). The Sodium Hypochlorite system is original, in poor condition, and has experienced multiple failures, creating a safety hazard for the operators. Additionally, this equipment is housed in the same building as the sulfuric acid dosing system with only a fiberglass dividing wall. If both systems were to experience a leak at the same time, that situation could generate poisonous chlorine gas;

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- Gas Turbine Generator (“GTG”)/ Steam Turbine Generator (“STG”) Replace Covert Units 1 through 3 Rollup Doors (\$535,000). The Covert Plant faces a significant operational challenge due to the absence of overhead roll-up doors on the south side of the power block building. This infrastructure limitation necessitates the removal of building panels to facilitate the ingress and egress of large equipment, such as STGs and GTGs, during major outages. This project will install insulated rollup doors with electrical power. By installing insulated roll-up doors, the Covert Plant can eliminate the time-consuming and costly process of panel removal and reinstallation. This upgrade streamlines access for large equipment, reducing downtime and associated labor costs. In addition, the insulated design and weather stripping of the Model 625 doors provide significant protection against cold air infiltration, safeguarding critical equipment during outage periods in cold weather;
- Netmation (Operating System & 4S) - Unit 2 (\$391,667). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Netmation (Operating System & 4S) - Unit 3 (\$300,833). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Gas Compressor Controls Replacement (Programmable Logic Controller (“PLC”) replacement) (\$424,4000). Gas Compressors (two in total) operate using a local control network consisting of a human machine interface (“HMI”) (Panel View 1000) and Allen Bradley PLC five controllers. This equipment has reached end of life and replacements are no longer available. The Covert site currently has one failed board in service. This project would utilize existing panels and replace the equipment with an Allen Bradley ControlLogix solution and PanelView Plus 7;
- Covert Units 1, 2, and 3 – MV90 Revenue Meters for MISO (\$570,000). The scope of this project is the replacement of the existing meters utilized to record power flows for purposes of reporting to MISO for market settlement;
- Linear Variable Differential Transformers (“LVDT”) Positioning Sensor – Unit 1 Fuel Control Valves (\$737.930). The scope of this project is to replace the Yokogawa 5516 mechanical type position sensors with LVDTs. The replacement is to include the following devices, Main “A” pressure control fuel valve sensor, Main “B” pressure control fuel valve sensor, Main flow control fuel valve sensor, Pilot pressure control fuel valve sensor, and the pilot flow control fuel valve sensor and compressor bypass actuator. The benefits of this project include reduced maintenance, improved accuracy, and higher long-term reliability due to the removal of the mechanical linkages and converting to a non-contact mechanism;

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The Covert Mitsubishi Power Gas turbines are equipped with Yokogawa 5516 mechanical linkage type position sensors. The Yokogawa position sensors are used to detect the position of the fuel control valves, bypass valve actuators, and the Inlet Guide Vanes. These valves and their position are critical as they control turbine output which allows more load on the generator and meets load demand. The Yokogawa 5516 position sensors are obsolete, and Yokogawa has announced that the 5516 position sensors are no longer manufactured as of March 31, 2015, no longer supported, and parts are no longer available. Mitsubishi Power recommends eliminating the Yokogawa mechanical linkage position sensors;

- Covert Base Outage Capital (\$443,333). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages; and
- Twenty additional projects at Covert totaling \$1.650 million which support safety, security, and reliability, with each project representing \$201,667 or less in capital expenditures. These projects include load commutated inverter Replacements, Unit 2 Power Distribution Center ("PDC") Battery Replacement, Electronic Overspeed protection, site small capital, LVDT Positioning Sensor – Unit 2, and SCR/CO Replacement - Unit 1.

Q. What is the basis for the projected \$61.483 million capital investment in the projected test period?

A. The projected \$61.483 million capital investment in the projected test period will fund numerous projects at the Covert Plant. Ten of these projects are greater than \$1 million, and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 1 through 10. The basis for these projects is described below:

- Purchase of site spare GSU transformer (\$4,500,000). Covert Generating Station consists of three gas turbine powered plants and three steam turbine powered plants placed in a one-on-one combined cycle configuration. The units transmit their power to the grid via GSU transformers. Each gas turbine powered unit feeds the secondary winding of a three-winding transformer, while the associated steam powered unit feeds the tertiary winding of the transformer. The GSU is rated for 500 MVA with forced oil and forced air. If a GSU were to fail, then the associated turbines would not be able to transmit power and would not be able to generate market value for Consumers Energy and its customers. The lead time for a GSU is currently three-to-four years and spare units at other facilities typically do not exist, especially for this more unique design application;

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This project provides a spare GSU for Covert which: 1) Greatly reduces unit downtime in the event of GSU issues or failure requiring removal and lowers the total financial losses in such events; 2) Allows for easier engineering design and planning to install a spare or replacement GSU ahead of any emergent installation needs; 3) Mitigates potential issues from installing GSUs not specifically designed for this location, system or application and/or doing it multiple times in a short time period; 4) Would allow for Consumers Energy to enter lease agreements with other utilities who may be in need of a spare to recover some costs of the spare purchase over time; and 5) The oil analysis of Covert transformers revealed the presence of chemicals for corrosive sulfur. Mitigating actions are being taken, however, this failure mode puts these transformers at increased risk of failure;

- Office Space Consumers Energy Warehouse with Loading Dock (\$1,816,667). The scope of this project is to build out the existing warehouse and add a loading dock. The existing warehouse does not meet the needs for the upcoming major outages, or plant maintenance in the future. The addition of a loading dock will provide for safer and efficient loading/unloading of trucks. In addition, the current onsite office space is inadequate, and it will be expanded;

Cooling Tower Gearboxes (\$1,039,192). The Covert Generating Station Cooling Tower Fan Gearbox Replacement Project addresses critical operational issues stemming from the end-of-life status of gearboxes after over 20 years of service. These gearboxes are essential for cooling tower fan operations, affecting the station's overall efficiency and reliability. The scope of this project is to replace the existing cooling tower gearboxes with gearboxes from the same manufacturer, an alternative that avoids additional modifications. Covert operates three 6-cell cooling towers corresponding to each of its units. These cooling towers play a crucial role in the station's operational efficiency by facilitating the removal of residual heat from circulating water. This process is essential after the water has been utilized for condensing steam produced by the steam turbines. Operational challenges with the gearboxes include increased gearbox failures, inadequate heat removal due to malfunctioning cooling tower fans, and obsolete motor starters;

- Netmation (Operating System & 4S) - Unit 2 (\$1,458,333). The Covert gas generating station, operational since 2004, faces critical challenges with its outdated control systems. These challenges impact both operational efficiency and cybersecurity, necessitating an urgent upgrade to modern standards. The scope of this project is an extensive upgrade of the Covert Mitsubishi Turbine Control System to the latest version of Netmation, which includes the replacement of hardware, I/O modules, servers, workstations, network switches, and software to the latest architecture;
- Covert Units 1 through 3 Emerson DCS Evergreen (\$2,448,750). The scope of this project is to upgrade the DCS to the latest version in order to enhance security, gain compliance with enterprise standards, and achieve technological

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1 advancement. Covert, which has been operational since 2004, faces significant
2 challenges with its Emerson Ovation DCS. The system's obsolescence,
3 cybersecurity risks, and operational inefficiencies necessitate an urgent upgrade
4 to the latest version to enhance reliability, security, and compliance with
5 regulatory standards. The DCS that controls all equipment in the plant (along
6 with the Mitsubishi gas turbine controls), is Emerson Ovation DCS. It was
7 upgraded about 10 years ago to the current version. Emerson Ovation version
8 3.5.1 is no longer supported by Emerson or Microsoft. The Emerson Ovation
9 version 3.5 system entered a retired status in June 2019. The Windows
10 operating systems that are used by this version of Ovation are Windows 7 and
11 Windows Server 2008R2. Microsoft ended extended support of Server 2008R2
12 in January 2020.

13 The generation plant control systems are an important part of the nation's
14 Critical Infrastructure and fall under NERC CIP requirements. To keep the
15 Company's control systems secure, Consumers Energy must patch the
16 operating systems and applications that run its plants. The Company is no
17 longer able to patch and maintain these operating systems, such as Microsoft
18 Windows, or applications, such as Ovation, when they are no longer supported
19 by the manufacturers. The systems at Covert do not meet corporate
20 cybersecurity standards and are operating with security exception to the
21 Company's standards.

22 The cybersecurity tools (Power Water Cybersecurity Suite ("PWCS"))
23 being utilized for the Covert control network device patching and antivirus
24 protection require replacement to allow continued patching and protection with
25 a new DCS version. The current version of PWCS is nearing end of support
26 and requires updating to allow support of the latest Ovation versions.

27 The Balance of Plant ("BOP") control is achieved with the Ovation DCS.
28 Its architecture is comprised of controller and operator "drops" (processors and
29 PCs) that provide the control of the equipment with input/output ("I/O")
30 modules. Some of these I/O modules are in the same electrical cabinets that
31 contain the "controller drops" (processors). Other I/O is in "remote" electrical
32 cabinets, away from the "controller drops." The existing plant control is
33 comprised of many remote I/O cabinets throughout the site. The
34 communication modules to these cabinets have experienced failures in the past
35 that can trip the generating units offline. Power supplies in the Ovation cabinets
36 have reached the end of their recommend life and need to be replaced. The
37 architecture and components need to be upgraded and replaced with the latest
38 Ovation design.

39 The main controller drop that operates a large part of the BOP equipment
40 has had equipment and data link controls added to it over the years. It controls
41 equipment for all three (3) generating units. The controller drop needs to have
42 part of its I/O and logic split off to new controller drops. The partitioning of I/O

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1 to other drops should allow the upgrade and maintenance procedures to occur
2 and reduce the need of a site outage to perform these activities. Risk to unit
3 trips should be reduced to individual generating units instead of all units on the
4 site;

- 5 • Netmation (Operating System and 4S) – Unit 3 (\$1,504,167). The Covert gas
6 generating station, operational since 2004, faces critical challenges with its
7 outdated control systems. These challenges impact both operational efficiency
8 and cybersecurity, necessitating an upgrade to modern standards. The scope of
9 this project is an extensive upgrade of the Covert Mitsubishi Turbine Control
10 System to the latest version of Netmation, which includes the replacement of
11 hardware, I/O modules, servers, workstations, network switches, and software
12 to the latest architecture;

- 13 • Covert Plant LTSA (\$14,700,000). This is the capital portion for Mitsubishi
14 negotiated services that cover the planned normal maintenance of each
15 generating unit. The projected capital expenditures are based upon variable fees
16 paid to Mitsubishi for maintenance services which are based on an Effective
17 Fired Hour basis pursuant to the LTSA. Unlike the GE LTSAs for the Jackson
18 and Zeeland plants, there are no milestone payments associated with the fee
19 structure for the Mitsubishi LTSA. Based on the OEM's operating and
20 historical experience, if the Company executes the normal planned maintenance
21 and inspections according to the recommended schedules, the Company will
22 mitigate unexpected pre-mature failures of the equipment. This will help
23 maximize availability and, as a result, optimize customer value for the site.
24 Normal maintenance will ensure the Company continues reliable operation of
25 the units. During the bridge period and test year, the Company will be
26 conducting major inspections on all three generating units, and a portion of the
27 work to be performed is not covered in the LTSA, rather it is covered in the
28 LTSA extra work as described below;

- 29 • Covert Unit 1 LTSA extra work (\$1,437,717). The LTSA extra work is defined
30 as the work that is not covered under normal planned maintenance in the LTSA.
31 Based on historical outage experience there are typical discovery items found
32 on this style of gas turbines that are not part of the LTSA planned maintenance
33 scope. Some of the typical items not covered under the LTSA that need to be
34 addressed are labor and material to replace the following: blading, ammonia
35 delivery system, SCR catalyst, turbine rotors, cooling towers, and turbine
36 cooling air cooler. The major inspection for Covert Unit 1 begins on
37 February 1, 2026, just prior to the end of the test year, and ends on March 31,
38 2026. As such, a large portion of the LTSA extra work will not be requested in
39 this proceeding;

- 40 • Covert Unit 2 LTSA extra work (\$12,609,633). The LTSA extra work is
41 defined as the work that is not covered under normal planned maintenance in
42 the LTSA. Based on historical outage experience there are typical discovery
43 items found on this style of gas turbines that are not part of the LTSA planned

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1 maintenance scope. Some of the typical items not covered under the LTSA that
2 need to be addressed are labor and material to replace the following: blading,
3 ammonia delivery system, SCR catalyst, turbine rotors, cooling towers, and
4 turbine cooling air cooler. The major inspection on Covert Unit 2 begins on
5 February 1, 2025, and major work includes generator inspection, replacement
6 of the generator hydrogen seals, generator rewedge, diaphragm repairs, steam
7 turbine and generator bearing repairs, and HP stop and control valve
8 disassembly, inspection, cleaning, and repair. The Company's LTSA with
9 Mitsubishi Electric Power Products, Inc. ("MEPPI") does not cover this scope
10 of work; and

- 11 • Covert Unit 3 LTSA extra work (\$10,609,633). The LTSA extra work is
12 defined as the work that is not covered under normal planned maintenance in
13 the LTSA. Based on historical outage experience there are typical discovery
14 items found on this style of gas turbines that are not part of the LTSA planned
15 maintenance scope. Some of the typical items not covered under the LTSA that
16 need to be addressed are labor and material to replace the following: blading,
17 ammonia delivery system, SCR catalyst, turbine rotors, cooling towers, and
18 turbine cooling air cooler. The major inspection on Covert Unit 3 begins on
19 November 1, 2025, and major work includes generator inspection, replacement
20 of the generator hydrogen seals, generator rewedge, diaphragm repairs, steam
21 turbine and generator bearing repairs, and HP stop and control valve
22 disassembly, inspection, cleaning, and repair. The Company's LTSA with
23 MEPPI does not cover this scope of work.

24 The following projects are less than \$1 million, but are important to reliability:

- 25 • Excitation Replacement (\$761,667). The scope of this project is the
26 replacement of the steam turbine exciters. The existing excitation equipment is
27 obsolete, and the gas turbine exciters have already been replaced. A failure of
28 the steam turbine exciter could lead to both generators on the unit being out of
29 service until replacements can be found with a typical lead time of
30 18-24 months;
- 31 • Electronic Overspeed protection (\$678,333). The scope of this project is the
32 installation of an electronic overspeed trip upgrade. The plant has experienced
33 issues with their overspeed trip device in the past. The backup electronic
34 overspeed trip is reliable but is not redundant so that a single component failure
35 would not disable the trip. The primary protection on the steam turbines are the
36 mechanical overspeed trip mechanisms. The mechanical overspeed trip
37 mechanism must be tested (offline) periodically to ensure that its setpoint has
38 not changed and that it can trip the unit;
- 39 • Flame Detectors for Gas Turbine Wheel temperature Digital replacement
40 (\$397,083). The scope of this project is to replace the existing mechanical
41 flame detection system with digital flame detection system. The existing

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1 system is obsolete and has reliability issues that a new digital system would
2 resolve;

- 3 • SCR/CO Catalyst Replacement - Unit 2 (\$708,333). The scope of this project
4 is the replacement of the catalyst for the SCR. This replacement is based upon
5 the expected degradation of the exiting catalyst and effective operation of the
6 SCR is required to meet environmental regulations;

- 7 • SCR/CO Catalyst Replacement – Unit 3 (\$708,333). The scope of this project
8 is the replacement of the catalyst for the SCR. This replacement is based upon
9 the expected degradation of the exiting catalyst and effective operation of the
10 SCR is required to meet environmental regulations;

- 11 • Netmation (Operating System and 4S) – Unit 1 (\$375,000). The Covert gas
12 generating station, operational since 2004, faces critical challenges with its
13 outdated control systems. These challenges impact both operational efficiency
14 and cybersecurity, necessitating an urgent upgrade to modern standards. The
15 scope of this project is an extensive upgrade of the Covert Mitsubishi Turbine
16 Control System to the latest version of Netmation, which includes the
17 replacement of hardware, I/O modules, servers, workstations, network
18 switches, and software to the latest architecture;

- 19 • Balance Of Plant Valves – Unit 2 (\$590,000). The scope of this project is the
20 repair and/or replacement of balance of plant valves. The plant has a long list
21 of valves that require attention. The condenser bypass valves will be addressed
22 in the major outage scheduled for March 1, 2025 through March 31, 2025 and
23 they represent a large expense;

- 24 • Balance Of Plant Valves – Unit 3 -(\$590,000). The scope of this projects is the
25 repair and/or replacement of balance of plant valves. The plant has a long list
26 of valves that require extensive maintenance. The condenser bypass valves will
27 be addressed in the major outage scheduled for November 1, 2025 through
28 December 30, 2025 and they represent a large expense;

- 29 • Positioning Sensor – Unit 3 (\$687,500). The scope of this projects is to replace
30 the Yokogawa 5516 mechanical type position sensors with LVDTs. The
31 replacement to include the following devices, Main “A” pressure control fuel
32 valve sensor, Main “B” pressure control fuel valve sensor, Main flow control
33 fuel valve sensor, Pilot pressure control fuel valve sensor, and the pilot flow
34 control fuel valve sensor and compressor bypass actuator. The benefits of this
35 project include reduced maintenance, improved accuracy, and higher long-term
36 reliability due to the removal of the mechanical linkages and converting to a
37 non-contact mechanism. The Covert Mitsubishi Power Gas turbines are
38 equipped with Yokogawa 5516 mechanical linkage type position sensors. The
39 Yokogawa position sensors are used to detect the position of the fuel control
40 valves, bypass valve actuators, and the Inlet Guide Vanes. These Valves and
41 their position are critical as they control turbine output which allows more load

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on the generator and meets load demand. The Yokogawa 5516 position sensors are obsolete, and Yokogawa has announced that the 5516 position sensors are no longer manufactured as of March 31, 2015, are no longer supported and parts are no longer available. Mitsubishi Power recommends eliminating the Yokogawa mechanical linkage position sensors;

- SCR/CO Catalyst Replacement – Unit 1 (891,667). The scope of this project is the replacement of the catalyst for the SCR. This replacement is based upon the expected degradation of the exiting catalyst and effective operation of the SCR is required to meet environmental regulations;
- Covert Base Outage Capital (\$383,333). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages;
- LVDT Positioning Sensor - Unit 2 (645,833). The scope of this projects is to replace the Yokogawa 5516 mechanical type position sensors with LVDTs. The replacement to include the following devices, Main "A" pressure control fuel valve sensor, Main "B" pressure control fuel valve sensor, Main flow control fuel valve sensor, Pilot pressure control fuel valve sensor, and the pilot flow control fuel valve sensor and compressor bypass actuator. The benefits of this project include reduced maintenance, improved accuracy, and higher long-term reliability due to the removal of the mechanical linkages and converting to a non-contact mechanism.

The Covert Mitsubishi Power Gas turbines are equipped with Yokogawa 5516 mechanical linkage type position sensors. The Yokogawa position sensors are used to detect the position of the fuel control valves, bypass valve actuators, and the Inlet Guide Vanes. These Valves and their position are critical as they control turbine output which allows more load on the generator and meets load demand. The Yokogawa 5516 position sensors are obsolete, and Yokogawa has announced that the 5516 position sensors are no longer manufactured as of March 31, 2015, no longer supported, and parts are no longer available. Mitsubishi Power recommends eliminating the Yokogawa mechanical linkage position sensors; and

- Eighteen additional projects at Covert totaling \$1.941 million which support safety, security, and reliability, with each project representing \$408,333 or less in capital expenditures. These projects include BOP Valves - Unit 1 MI, Unit 1 and Unit 3 PDC Battery Replacement (NERC), Load Commutated Inverter replacements, Gas Turbine - Units 1 through 3 Evaporator Media, and site small capital.

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Karn Units 1 and 2

Q. Please explain the Company's projected capital investment for the 14-month projected bridge period ending February 28, 2025 and the projected test year ending February 28, 2026 for Karn Units 1 and 2.

A. The Company does not plan to make any capital investments on Karn Units 1 and 2 in the 14-month projected bridge period ending February 28, 2025 or the projected test period ending February 28, 2026, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 15, columns (h) and (j), respectively, due to their retirement on May 31, 2023.

Karn Units 3 and 4

Q. Please explain the Company's projected capital investment for the 14-month projected bridge period ending February 28, 2025 and the projected test year ending February 28, 2026, for Karn Units 3 and 4.

A. The Company plans to invest \$17.119 million in the projected bridge period and \$7.287 million in the projected test period, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 22, columns (h) and (j), respectively.

Q. What is the basis for the projected \$17.119 million capital investment in the 14-month projected bridge period?

A. The projected \$17.119 million capital investment will fund numerous safety, regulatory compliance, reliability, and infrastructure projects at Karn Units 3 and 4. There are six projects which are greater than \$1 million, and these projects are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 14 through 19.

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1 **Q. Did the Order in the Company's 2023 Electric Rate Case (Case No. U-21389) establish**
2 **any specific requirements for any of the Karn site projects?**

3 A. Yes. Paragraph C on page 309 of the March 1, 2024 Order in Case No. U-21389 required
4 the following:

5 "Consumers Energy Company shall file in its next general
6 electric rate case an alternatives analysis addressing the
7 replacement of the Karn Unit 3 Cooling Tower internal
8 structure, including information on the most cost-efficient
9 solution and alternatives to full replacement as described in
10 this order."

11 **Q. What is the scope of the project?**

12 A. The scope of this project is the replacement of the structural timbers, remaining stacks, and
13 fan blades on Karn Unit 3's cooling tower. The wooden structure is original equipment
14 and has decayed since its installation. The cooling tower provides cooling water for the
15 condenser. The wooden cooling tower structure supports 18 large fans that pull air through
16 the water to drive the evaporation process to cool the water. The wooden structure also
17 supports large water pipes that carry the cooling water to the fill. The water flow to the
18 tower is approximately 240,000 gallons per minute. The entirety of this weight is
19 supported by the wooden structure as it is conveyed to the tower and cascades over the fill.
20 Implementation of this project will provide for reliable operation of Karn Unit 3 through
21 its retirement in 2031. The projected cost for this project in the 14-month bridge period is
22 \$6.0 million.

23 **Q. Has the Company performed an alternative analysis?**

24 A. Yes. The Company has created a concept approval to document its evaluation of the project
25 and the potential alternative. The concept approval is presented as Exhibit A-45 (RTB-6).

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As established in Exhibit A-45 (RTB-6), the cooling tower internal structure was in poor condition and viable options were limited.

Q. Please discuss the basis for the remaining projects for Karn Units 3 and 4.

A. The basis for the remaining projects greater than \$1 million are described below:

- Karn Units 3 and 4 Sync Wire Replacement (\$1,260,000). The scope of this project is the replacement of the existing copper communication cables between the plant and Hampton Substation. The replacement will consist of fiber optic communication cable from Hampton Substation to the plant and the replacement of Karn Units 3 and 4 generating unit line protection relays, pilot wire differential line protection relaying, telemetry, and control communication at Hampton Substation. Telemetry and control include but are not limited to breaker position indication, breaker control, transfer trip, bus voltage, and current indication. The Karn Units 3 and 4 auto-synchronizing relay is obsolete. This project will provide a modern reliable communication medium between Karn Units 3 and 4 and Hampton Substation, where the generator synchronization breakers reside. This medium will allow for a reliable means of communication between Karn Units 3 and 4 and the Hampton Substation, thereby reducing the risk of possible failure of the units to synchronize correctly or to trip the units offline for a fault event; potentially causing damage to the generator and turbine, resulting in decreased plant reliability and increased expense;
- Karn Units 3 and 4 Plant Heating Boiler (\$1,760,000). The scope of this project is the continuation of the installation of boilers for heating Karn Units 3 and 4. The remaining work to be accomplished in the bridge period includes the following:
 1. Installation of Gas Regulators which required modifications to the already installed gas piping;
 2. Installation new Steam Check Valve;
 3. Conduct Preliminary Air Check prior to hydro to identify any leaks before the State Boiler Inspector was on site;
 4. Install Sump Drains at multiple locations;
 5. Replace Day Tank Steam System Valves;
 6. Install additional Steam Traps;
 7. Install stack extension and stack drains;
 8. Install additional heat trace and insulation; and
 9. Install enclosure around Deaerator.

The Plant Heating Boilers Project is a strategic initiative aimed at upgrading the plant heating system at Karn Power Station. The project involves the procurement and installation of two smaller, more efficient boilers for continuous plant heating. Prior to implementing this project, the existing

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auxiliary boilers were utilized, and the auxiliary boilers were both inefficient and unreliable for continuous plant heating. Originally, the auxiliary boilers were to be used for plant heating and were to be addressed as part of the Karn Units 3 and 4 separation as previously discussed in this direct testimony;

- Karn Unit 3 Combustion Air Heaters (\$2,200,000). The combustion air heaters A and B had excessive tube leaks that were pressure tested and plugged during the fall 2022 outage. The B section has the worst damage with an estimated 50% of the tubes out of service. The scope of work for this project includes the replacement of two sections of the combustion air heater. The heater condition is causing a 68 MW derate on the unit;
- Karn Unit 4 DCS and Simulator Upgrade Evergreen (\$1,363,000). This project replaces the Karn Unit 4 Ovation DCS with the latest version available at the time of the project. The system is currently running on a VMware virtualized system. The system was installed in 2015 and software upgraded in 2019. This Evergreen will replace the existing Ovation Software, Operating Systems, and miscellaneous upgrades, the controller drops, and rack-mounted servers will be replaced for this upgrade. The DCS must be upgraded at a four-to-five-year upgrade cycle to maintain reliable control and provide recent operating systems and applications that are patchable. Vendor life cycle for DCS versions is generally a five-year cycle. After five years they enter a retired state and are no longer patched. Microsoft Operating Systems are on a limited life basis, and they reach the end of “extended support” and no longer get security patches. Corporate policies require all systems to be patched regularly along with Anti-Virus updates; and
- Karn Unit 3 DCS and Simulator Evergreen (\$1,507,000). This project replaces the Karn Unit 3 Ovation DCS with the latest version available at the time of the project. The system is currently running on a VMware virtualized system which was installed in 2019. This Evergreen will only replace the existing Ovation Software, Operating Systems, and miscellaneous upgrades. The controller drops and rack-mounted servers will not be replaced for this upgrade. The DCS must be upgraded at a four-to-five-year upgrade cycle to maintain reliable control and provide recent operating systems and applications that are patchable. Vendor life cycle for DCS versions is generally a five-year cycle. After five years they enter a retired state and are no longer patched. Microsoft Operating Systems are on a limited life basis, and they reach the end of “extended support” and no longer get security patches. Corporate policies require all systems to be patched regularly along with Anti-Virus updates.

The following projects are less than \$1 million, but are important to reliability:

- Karn Units 3 and 4 Ductwork Expansion Joint Replacement – Induction Draft (“ID”) Fans to Stack (\$710,667). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Karn Units 3 and 4;

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- 1 • BOP Capital tooling/valves/instrumentation (\$933,333). This project spans the
2 14-month bridge period and the test year, and its basis is included in my
3 discussion of the test year capital projects for Karn Units 3 and 4;
- 4 • Karn Units 3 and 4 - 250v Battery Bank Replacement (\$360,000). Replace the
5 250V battery with an equivalent and replace the charger with greater ampacity
6 to handle full load if batteries die. New battery bank will make Karn Units 3
7 and 4 more reliable and safer to operate. New battery bank and battery charger
8 will be in operation until the retirement of Karn Unit 3 and 4. New battery bank
9 will improve availability of backup DC bearing and seal oil pumps. Karn Units
10 3 and 4 utilizes a 250-volt battery bank to run emergency bearing oil pumps &
11 seal oil pumps in case of an emergency, like loss of AC power while the turbine
12 is hot. The 250-volt Battery bank was installed in 2014. Design life of these
13 batteries is approximately 10-12 years. The current batteries are rated for
14 910 amp hours. Based on the historical data, the 250-volt battery bank has been
15 depleted/discharged a number of times. This has caused battery cells to
16 operate/perform beyond their duty. A load test was conducted on this battery
17 bank in 2022 and the results were marginal. A battery bank can serve the
18 worst-case scenario load for approximately one hour only, which is less than
19 the Company's recommended time for the turbine generator to come to stand
20 still;
- 21 • Karn Unit 4 voltage regulator (\$400,000). The scope of this project is the
22 installation of a "Digital Front End" upgrade to the GE Automatic Voltage
23 Regulator on Karn Unit 4. The existing voltage regulator was installed around
24 2004 and was phased out of production in 2011. It became legacy equipment
25 on March 1, 2021 and is no longer available. The software used to configure
26 the existing system runs on Windows XP and is no longer patched or
27 supported. The hardware will be upgraded from EX2100 to EX2100e
28 architecture. This also includes ethernet switches, operator interface, GE
29 project management, operation manuals, drawings, technical direction of
30 installation and design package. Post maintenance testing and MOD-26 testing
31 are also being included; and
- 32 • Five additional projects at Karn Units 3 and 4 totaling \$0.625 million which
33 support safety, security, and reliability, with each project representing \$310,000
34 or less in capital expenditures. These projects include rewind of the Karn Unit 4
35 house service air compressor motor, replacement of the processors for the Karn
36 Unit 3 automatic voltage regulator, Karn Units 3 and 4 tank farm storage tank
37 heating line replacement, Karn Units 3 and 4 plant heating boilers, and
38 replacement of the Karn Units 3 and 4 stack ladder fall protection system.

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1 **Q. What is the basis for the projected \$7.287 million capital investment in the projected**
2 **test period?**

3 A. The projected \$7.287 million capital investment in the projected test period will fund five
4 projects. Two of these projects are greater than \$1 million and are presented on Exhibit
5 A-12 (RTB-3), Schedule B-5.2, page 9, lines 18-19. The basis for these projects is
6 described below:

- 7 • Karn Unit 4 Replacement of Ductwork Insulation and Lagging (\$4,800,000).
8 The scope of this project is to replace the lagging and insulation on all the
9 ductwork from the building out to the stack. The existing lagging and insulation
10 needs to be removed, the underlying steel fixed as necessary, and new insulation
11 and lagging installed. The steel structure that the ductwork lagging is attached
12 to is severely corroded. This has allowed multiple random failures of the
13 lagging, resulting in a safety concern due to pieces of lagging falling to the
14 ground or becoming airborne during wind events; and
- 15 • Ductwork Expansion Joint Replacement – ID Fans to Stack (\$1,900,000). This
16 project will replace all expansion joints and entry doors between the ID Fans
17 and the stack. All expansion joints between the ID Fans and the Stack are
18 beyond their end of life and suspected to be severely degraded based upon the
19 condition of expansion joints found during the Karn Unit 3 Breaching project.
20 Failed expansion joints will need to be replaced to maintain environmental
21 compliance. This scope of work will make the ductwork air-tight again to
22 maintain environmental compliance.

23 The following projects are less than \$1 million, but are important to reliability:

- 24 • Capital tooling/valves/instrumentation (\$500,000). This project supports
25 capital expenditures for replacement of small valves, instrumentation, tools,
26 equipment, pumps, and motors at Karn Units 3 and 4 during the projected test
27 year; and
- 28 • Two additional projects at Karn Units 3 and 4 totaling \$0.087 million which
29 support reliability, with each project representing \$66,667 or less in capital
30 expenditures. These projects include overhaul of the Karn Unit 4 condenser
31 circulating water pumps and project closeout of Karn Units 3 and 4 sync wire
32 replacement.

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Zeeland Plant

Q. Please explain the Company's projected investment for the 14-month projected bridge period ending February 28, 2025 and projected test year ending February 28, 2026 for the Zeeland Plant.

A. The Company plans to invest \$48.518 million in the 14-month projected test period and \$50.929 million in the projected test year at the Zeeland Plant, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 29, columns (h) and (j), respectively. These capital expenditures will be facilitated, in part, by short outages in the spring and fall of the 14-month projected test period and the projected test year. The Company has an LTSA with GE that covers many reliability investments at the Zeeland Plant.

Q. What is the basis for the projected \$48.518 million capital investment in the 14-month projected bridge period?

A. The projected \$48.518 million capital investment will fund numerous safety, regulatory compliance, reliability, and infrastructure projects at the Zeeland Plant. There are five projects which are greater than \$1 million, and these projects are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 9 through 13. The basis for these projects is described below:

- Phase I Gas Turbine Advanced gas path replacement and axial fuel staging (\$20,356,250). This project spans the projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Zeeland Plant;
- Zeeland Plant LTSA (\$9,520,000). This project spans the projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Zeeland Plant;
- Zeeland Unit 5 GSU Rewind (\$5,546,538). The scope of this project will remove the failed Zeeland Unit 5 GSU transformer and send it out for rewind and overhaul to support long-term reliable operation. This project also installs a leased GSU transformer. The Zeeland Unit 5 GSU Transformer, which

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1 outputs electricity from the generator to the grid, was showing signs of
2 imminent failure as indicated by hydrocarbon gasses being continuously
3 generated at rates above Institute of Electrical and Electronics Engineers (IEEE)
4 recommended levels. The time to failure could not be predicted and could have
5 been catastrophic in nature. Previous intrusive internal inspection and testing
6 work in fall of 2022 was able to identify and replace some degraded parts but
7 ultimately not able to locate the source of gas generation;

- 8 • Zeeland Plant HRSG Casing Replacement (\$2,097,620). The HRSG is
9 designed to recover and recycle heat energy from a gas turbine exhaust.
10 A HRSG produces steam that is used to drive a steam turbine. During recent
11 inspections of the HRSGs at the Zeeland Plant, extensive outer casing corrosion
12 has been identified in particular sections of the units. This condition creates the
13 risk of the studs, which hold on the insulation and liner panels, breaking loose
14 and liberating both insulation and liner sheets. The insulation then blows
15 downstream and fouls the HRSG tubes, requiring the unit to be shut down and
16 cleaned, then subsequent casing, insulation, and liner repairs. The affected
17 areas of casing need to be cut out and replaced with new casing; and
- 18 • Zeeland Plant LTSA supplementals not included in contract (\$3,925,000). This
19 project spans the projected bridge period and the projected test year, and its
20 basis is included in my discussion of projected test year capital projects for the
21 Zeeland Plant.

22 The following projects are less than \$1 million but are important to regulatory compliance
23 and reliability:

- 24 • Main Steam Non-return Valve Replacement (\$705,309). The scope of this
25 project is to replace both main steam check valves. During inspections in the
26 Fall 2018 outage, cracking was noted on both of the main steam stop-check
27 valve body internals. With continued plant operation, the cracks are expected
28 to continue to grow, potentially extending through the valve seat, making the
29 valve unable to seal completely. The cracks can also grow to a through-wall
30 crack, resulting in a steam leak. This cracking is a known issue with these types
31 of valves, and is driven by expansion differentials primarily on startup and
32 shutdown. This cracking had initially been noted during a pipe borescope
33 inspection in 2011;
- 34 • Zeeland - Purchase of Site Spare GSU Transformer (\$589,607). This project
35 spans the projected bridge period and the projected test year, and its basis is
36 included in my discussion of projected test year capital projects for the Zeeland
37 Plant;
- 38 • 199 and 499 345kV Breaker Replacement (\$623,483). The scope of this project
39 is to replace the 199 and 499 circuit breakers with a type which does not exhibit
40 the failure modes exhibited by the existing design. The existing breakers have
41 a critical design flaw such that an individual pole or poles may not latch open

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1 when required. The pole's failure to latch open has the potential to result in lost
2 generation, loss of power to the entire Zeeland Substation, and/or equipment
3 damage;

- 4 • Site Commons Road Resurfacing (\$554,167). This project spans the projected
5 bridge period and the projected test year, and its basis is included in my
6 discussion of projected test year capital projects for the Zeeland Plant;
- 7 • Gas Turbine Inlet Filters Replacement (\$390,000). The scope of this project is
8 to replace canister filters. The filters are required to be replaced every five years
9 and must be accomplished during an outage. The purpose of the project is to
10 maintain the integrity of the filters to prevent material ingress to the turbines;
- 11 • ZGS – GE DCS Evergreen (\$600,000). The scope of this project is to upgrade
12 the Zeeland Plant Turbine Controls DCS with the latest version available at the
13 time of the project. The system is currently running on a VMware virtualized
14 system which was installed in 2020. This Evergreen will only replace the
15 existing GE Software, Operating Systems, and miscellaneous upgrades. This
16 project will allow the latest versions of control software and operating systems
17 to be used for reliable operation and control of the generating units. The latest
18 feature enhancements are also available for operation. This will also allow the
19 latest patches to be applied by the cyber security Emerson PWCS application.
20 The DCS must be upgraded at a four-to-five-year upgrade cycle to maintain
21 reliable control and recent operating systems and applications that are patchable.
22 The vendor life cycle for DCS versions is generally five years. After five years
23 they enter a retired state and are no longer patched. Microsoft Operating Systems
24 are on a limited life basis, and they reach the end of "extended support" and no
25 longer get security patches;
- 26 • ZGS – 299 345kV Breaker Replacement (\$510,000). The scope of this project
27 is to replace the 299 circuit breaker with a type which does not exhibit the
28 failure modes exhibited by the existing design. The existing breaker has a
29 critical design flaw such that an individual pole or poles may not latch open
30 when required. The pole's failure to latch open has the potential to result in lost
31 generation, loss of power to the entire Zeeland substation, and/or equipment
32 damage;
- 33 • Zeeland Plant Base Outage Capital (\$482,555). Base outage capital covers the
34 replacement parts and issues found during turbine/generator inspections and the
35 major discovery issues found during annual unit outages; and
- 36 • Seventeen additional projects at the Zeeland Plant totaling \$2.617 million
37 supporting safety, reliability, regulatory compliance, infrastructure, and
38 operations, with each project representing less than \$337,200 or less in
39 expenditures. These projects include Install Combustion Turbine Overspeed
40 Software, Phase 2 599 and 699 345kV Breaker Replacement, Zeeland
41 combined cycle GT2A GT2B Air Filter Replacement, MarkVIe Controller
42 Replacement Project, 480V Circuit Breaker Coordination System Replacement,

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CT Autotune Software Replacement, boiler feedwater pump, and small tools, pumps, motors, valves, and instrumentation.

Q. What is the basis for the projected \$50.929 million capital investment in the projected test year?

A. The projected \$50.929 million capital investment in the projected test year will fund numerous safety, regulatory compliance, reliability, and infrastructure projects at the Zeeland Plant. There are six projects which are greater than \$1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 12-17. The basis for these projects is described below:

- Zeeland Plant LTSA (\$8,181,333). This is the capital portion for negotiated services that cover the planned normal maintenance of each unit based on its equivalent operating factor fired hours. The planned maintenance includes the following support services (OEM on-site/off-site technical support, engineering, and labor). Typical activities include borescope inspections, capital repairs, unit tuning, addressing service bulletin requirements, and on-site inspections. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected pre-mature failures of the equipment. This will help minimize ROR and it will optimize customer value for the site. Normal maintenance will ensure the Company continues reliable operation of the units;
- Zeeland Plant LTSA supplementals not included in contract (\$4,275,000). The LTSA supplemental work is defined as the work that is not covered under normal planned maintenance in the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items that need to be addressed are labor and material to replace the following: blading, combustion cans, ignitors, vanes/bushings, and any components on the compressor end as the compressor is not covered under the LTSA;
- Zeeland Site Spare GSU Transformer (\$6,449,004). The scope of this project is the procurement of a spare GSU transformer for the Zeeland site. The Zeeland Plant consists of four gas turbine powered plants and one steam turbine powered plant. The units transmit their power to the grid via GSU transformers. If a GSU were to fail, then the associated turbine would not be able to transmit power and would not be able to generate energy and capacity

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1 market value for Consumers Energy and its customers. For the Zeeland
2 combined cycle plant, the combustion turbine requires the operation of the
3 steam turbine, therefore the loss of the steam turbine's GSU transformer would
4 effectively limit operation of two connected combustion turbine units. The
5 lead time for a GSU transformer is currently three-to-four years and spare units
6 at other facilities are not viable replacements due to compatibility and
7 installation challenges. This project would purchase a spare GSU transformer
8 that is sized to be able to replace any of the existing transformers on site and
9 develop redundancy for any minor power upgrades in the future. As previously
10 discussed, the GSU transformer for Zeeland Unit 1 has failed and is being sent
11 out for rewind;

- 12 • Phase I Gas Turbine Advanced gas path replacement and axial fuel staging
13 (\$25,743,740). The scheduled Major Inspection outages in 2025 for the Phase 1
14 gas turbines at Zeeland Generating Station present an ideal time for substantial
15 technological advancements. This project proposes the integration of Advanced
16 Gas Path ("AGP") and Axial Fuel Staging ("AFS") technologies during these
17 outages, aimed at boosting turbine performance and operational flexibility.
18 A more detailed analysis of this project is presented in Exhibit A-46 (RTB-7):
19 Zeeland Phase 1 Gas Turbine upgrades;
- 20 • Generator Rewinds (\$2,174,167). There are multiple Technical Information
21 Letters (Bulletins) from the OEM (GE) involving the brazed connections under
22 the retaining rings that need to be addressed as well as multiple turn shorts
23 potentially evident by the OEM 2021 health assessments for Zeeland Units 3
24 and 4. The impacts of turn shorts include: uneven heating of the rotor which
25 will lead to increased seismic vibrations that can create multiple failure
26 scenarios for a field and possible induced rotor bow, higher field current
27 required to match original design which can result in higher heating effects and
28 escalated failure modes, and damage to the retaining rings which will further
29 escalate the vibrational issues. During the major overhaul, the generator rotors
30 will be removed and replaced/rewound, correcting the issue with the
31 connections and shorted turn issue, allowing the units to run to the anticipated
32 end of life; and
- 33 • Phase II Turbine Replacements (\$1,884,167). The scope of this project replaces
34 the existing rotor with a new rotor, giving another 144,000 hours of operation
35 which would enable operation until the next rotor replacement out to
36 approximately the year 2045. Also included in this scope is new compressor
37 stator vanes due to the compressor being 20 years old; the best way to restore
38 the compressor to like-new condition is to replace the stationaries when the
39 blades will already be replaced. Lastly, the exhaust frame will be upgraded to
40 a robust exhaust frame due to reliability issues over the years, and the rotor
41 replacement being an appropriate time to replace the exhaust frame.

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Several other critical projects which are less than \$1 million but are important to reliability and infrastructure include:

- Zeeland combined cycle SCR Catalyst Replacement (\$417,500). The scope of this project is to replace the SCR catalyst to maintain NOx reduction on gas turbine emissions;
- Site Commons Road Resurfacing (\$395,833). The scope of this project is to perform continued resurfacing of site roads. Several roads require widening to ensure safe 2-way vehicle travel (e.g. road behind substation). Roads/driveways on site require continuous maintenance. The objective of the project is to ensure roadways are safe for both vehicle and pedestrian travel;
- Zeeland Plant Base Outage Capital (\$424,444). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during unit outages; and
- Nine additional projects at the Zeeland Plant totaling \$0.984 million support reliability and operations, with each project representing \$241,667 or less in expenditures. These projects include Unit 5 Battery Replacement, Phase II Unit 3 and 4 battery monitoring system, compressed air system replacement, boiler feedwater pump replacement, and small pumps, motors, valve, instrumentation, tools, and equipment.

Jackson Plant

Q. Please explain the Company's projected investment for the 14-month bridge period ending February 28, 2025 and test year ending February 28, 2026 for the Jackson Plant.

A. The Company plans to invest \$19.130 million in the 14-month projected bridge period and \$14.965 million in the projected test year at the Jackson Plant, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 36, columns (h) and (j), respectively. This will be facilitated by short outages in the fall of 2024 and 2025. The Company has a LTSA with GE to cover many reliability issues at the Jackson Plant.

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1 **Q. What is the basis for the projected \$19.130 million capital investment in the 14-month**
2 **projected bridge period?**

3 A. The projected \$19.130 million capital investment in the 14-month projected bridge period
4 will fund numerous safety, regulatory compliance, reliability, and infrastructure projects.
5 There are two projects which are greater than \$1 million, and they are presented on Exhibit
6 A-12 (RTB-3), Schedule B-5.2, page 8, lines 7-8. The basis for these projects is described
7 below:

- 8 • Jackson Plant LTSA (\$12,337,500). This project spans the 14-month projected
9 bridge period and the projected test year, and its basis is included in my
10 discussion of projected test year capital projects for the Jackson Plant; and
- 11 • Jackson Plant LTSA Extra Work (\$2,908,333). This project spans the
12 14-month projected bridge period and the projected test year, and its basis is
13 included in my discussion of projected test year capital projects for the Jackson
14 Plant.

15 Several other critical projects which are less than \$1 million but are important to reliability
16 and infrastructure include:

- 17 • Feedwater Desuperheater Valve Replacement (\$831,433). The scope of this
18 project is to install feedwater control valves and separate lance spray nozzle
19 assemblies that spray small amounts of water into steam flow continuously.
20 The HRSG 1-6 superheat ("SH") Steam Desuperheater Feedwater valves have
21 had very short life spans since original construction. There are several issues
22 that cause the valves to wear out quickly. The valves inherently cycle frequently
23 open and closed due to the boiler running close to high pressure ("HP") Steam
24 Outlet temperature setpoint at gas turbine baseload, without duct firing. This
25 has been reduced recently by a study completed by engineering and GE to allow
26 the HP Steam temperature to be increased from the original 750 degrees
27 Fahrenheit up to 770 degrees Fahrenheit. This change did cause the valves to
28 cycle open/close less frequently, but it did not result in a substantial
29 improvement in valve life. The brunt of the wear is absorbed by the HP FW
30 Autoblock valve, which when it begins to leak by, causes the SH Steam
31 temperature to fall. The HP FW Control Valve wears out quickly as well.
32 Typically, when this occurs the leak by accelerates quickly to the point which
33 the manual HP FW isolation valve upstream must be closed when the unit is
34 not duct firing in order to maintain adequate superheated steam temperature;

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- LM6000 Beckwith Relay Replacement (\$391,667). The scope of this project seeks to replace the LM6000 Generator Protective Relays with direct replacement relay upgrades and install test facilities in a pre-planned fashion. This will protect the generation assets and avoid issues with the obsolescence of the existing equipment. Jackson Units 1 through 6 are currently protected with Beckwith M3420 Relays that are obsolete. The long lead time replacement M-3425A relays have been purchased, and are awaiting installation.

In addition to being obsolete, the existing relays have limited, or no means for communication, fault analysis, troubleshooting, and event recording following an electric fault event. The current relays also do not have external test facilities for periodic maintenance. Because of this, the relays need to be un-wired to test, and then rewired. This increases maintenance time, as well as exposes the plant to unplanned operations due to human error;

- Base Outage Capital (\$350,000). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Jackson Plant;

- Jackson Site 480V Breaker (WavePro) Replacement (\$267,000). The 480V circuit breakers each have a small control box that senses the amount of current thru the breaker and trips the breaker for a fault. These trip modules have electronic components normally expected to last 10 years, and some are presently failing after 20 years of service. Since these trip modules are no longer made, a failure requires complete replacement of the module and current sensors at a qualified breaker repair shop. The scope of this project is to replace all 30 trip modules;

- Units 1-6 LM HP Start-up Vent Silencer Replacement (\$248,000). The degradation of the existing LM HP Start-Up Vent Silencers (original to plant) has resulted in exceeding the noise level limitations set forth in ST-001, Standard Technical and Site Data Specification. The specification states that the equipment shall not exceed 90 dBA when measured three feet from vent silencer opening at 90 degrees to the flow. The noise levels are disruptive to the surrounding neighborhood in addition to plant personnel. The replacement of three silencers will reduce the noise of current silencers, prevent additional excessive noise for plant personnel (OSHA) and surrounding community safety, and proactively avoid risk of violating city ordinances;

- JGS – Low Quality Sump Piping Replacement (\$256,535). The Jackson Plant has three sump pits to deal with wastewater throughout the plant. One of these sump pits is called the water treatment low-quality (“LQ”) sump, one the main low-quality sump, and one is the high-quality (“HQ”) sump. The water treatment LQ sump deals with most of the wastewater that comes from the plant including reverse osmosis backwash discharge, floor drains and miscellaneous sources. The main LQ sump takes transformer secondary containment drains. The HQ sump handles blow down condensate from the running units. Each

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1 sump pit has two pumps that operate off a multi-float switch level indicator.
2 The level indicators are reaching end of life. The water treatment LQ pumps
3 have a mean time between failures of about one year. The HQ sumps were
4 upgraded in 2019 with no failures at this time. The failures on the water
5 treatment sumps are due to failed bearings, worn impellers, volutes, and
6 casings. There is a large amount of dirt, oil, and other debris that get into the
7 water treatment LQ sump leading to wear of pump components and bearing
8 failures. The scope of this project is to replace the two sump pumps in the water
9 treatment LQ sump and the level indication on both LQ sumps. It is
10 recommended to install pumps with upgraded wear materials to help with the
11 erosion issue and install sealed greased bearings. The level transmitters are also
12 beginning to fail as the switches do not always actuate when they are supposed
13 to. The level transmitters will be replaced with radar level transmitters. The
14 sumps are locally controlled with an audible alarm. This project would also
15 bring control and level indication into the DCS for the sump;

- 16 • JGS NOx Umbilical Replacements (\$300,728). The scope of this project is to
17 replace the heated sample line (umbilical) on Jackson Units 1 through 5 and 7
18 from the analyzer to the stack probe. The Continuous Emissions Monitoring
19 System (“CEMS”) and associated umbilicals have been in service since 2002.
20 As a result of the heat trace failure on the LM6 umbilical in 2020 and the visual
21 condition of the polyurethane jacket, the remaining umbilicals were inspected.
22 Similar cracking and poor installation practices were observed. To avoid unit
23 downtime in the future, the Company determined that a project should be
24 initiated to replace the remaining units’ umbilicals. A three-year
25 implementation plan, replacing two umbilicals per year, is proposed to mitigate
26 risk. The new umbilicals will utilize a PVC jacket that is more resistant to
27 degradation and chemical attack. Post maintenance testing will be required
28 upon replacement including a relative accuracy test audit (“RATA”) to recertify
29 the CEMS. The combined-cycle combustion turbines at Jackson are subject to
30 specific NOx emission limits and monitoring requirements originating from
31 several environmental rules. For purposes of demonstrating compliance with
32 the NOx emission limits, JGS relies upon CEMS for each unit;

- 33 • Jackson Combustion Turbine Inlet Canister Filter Replacement (\$230,000).
34 The Jackson Plant is comprised of nine generating units. Jackson Units 1
35 through 7 draw combustion air in through a filter house which has integrated
36 filters to prevent dust, dirt, and debris from being pulled into the compressor
37 section of the turbine. The canister filters require periodic replacement to
38 maintain proper air flow to the engine. Over time the filters plug and reduce
39 the efficiency of the combustion turbine. If air flow is restricted enough, the
40 engine can stall due to lack of sufficient air causing catastrophic failure; and

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- Twelve additional projects at the Jackson Plant totaling \$1.009 million, with each individual project representing \$262,500 or less in expenditures. These projects include LM1-6 VIGV (variable inlet guide vane) Project, Major Motor and Pump Replacements, site small capital, DCS Evergreen replacement, and LM1-6 Steam injection trap replacements.

Q. What is the basis for the projected \$14.965 million capital investment in the projected test year?

A. The projected \$14.965 million capital investment in the projected test year will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There is one project which is greater than \$1 million, and it is presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, line 11. The basis for this project is described below:

- Jackson Plant LTSA (\$11,116,875). This is the capital portion for negotiated services that cover the planned normal maintenance of each unit based on its equivalent operating factor fired hours. The planned maintenance includes the following support services: OEM on-site/off-site technical support, engineering, and labor. Typical activities include borescope inspections, capital repairs, unit tuning, addressing service bulletin requirements, and on-site inspections. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected pre-mature failures of the equipment. This will help maximize availability and, as a result, optimize customer value for the site. Normal maintenance will ensure the Company continues reliable operation of the units.

Several other critical projects which are less than \$1 million but are important to reliability and infrastructure include:

- Jackson Plant LTSA Supplemental Work (\$350,000). The LTSA supplemental work is defined as the work that is not covered under normal planned maintenance in the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items that need to be addressed are labor and material to replace the following: blading, combustion cans, ignitors, vanes/bushings, and any components on the compressor end as the compressor is not covered under the LTSA;

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- 1 • Base Outage Capital (\$300,000). Base outage capital covers the replacement
2 parts and issues found during turbine/generator inspections and the major
3 discovery issues found during annual unit outages;
- 4 • JLM1-6 Variable Inlet Guide Vane (“VIGV”) Project (\$900,000). This project
5 will install new VIGV systems on six LM6000PC engines at the Jackson Plant.
6 The seventh LM6000PC engine has a partial installation already, and the project
7 will complete the VIGV system for this engine. For LM6000PC SPRINT gas
8 turbines, which the Jackson Plant has, the VIGV upgrade is expected to yield a
9 significant fuel efficiency improvement at part power. The average fuel
10 efficiency improvement at 70% of maximum power is greater than 2%. The
11 VIGV also helps minimize variable bypass valve (“VBV”) flow and pressure
12 levels, thereby reducing associated flow noise. The VIGV system improves
13 performance for both simple cycle and heat-recovery cycles when operating at
14 less than full load;
- 15 • GSU Transformer Site Spare (\$833,333). This project provides Jackson with a
16 reliable spare GSU to which it currently does not have access. The main
17 transformers (GSUs) are a single point of failure to delivering power from the
18 generators to the grid. For failure of one main transformer, lost generation
19 would be 47 MW to 104 MW, depending on which generator(s) are connected.
20 The lead time for a new transformer is three-to-four years, since every
21 transformer of this size is custom built, and a large quantity of special raw
22 materials is required. The Company’s spare transformers located at Campbell,
23 Karn, Lake winds, and Crosswinds do not have the correct voltage
24 (138kV-13.2kV-13.2kV) or correct winding configuration (WYE-DELTA) to
25 function at Jackson so they cannot be considered for use as spares;
- 26 • DCS Evergreen replacement (\$666,667). This project replaces the GE DCS
27 with the latest version available at the time of the project. The system is
28 currently running on a VMware virtualized system. The system was installed
29 in 2020. This Evergreen will only replace the existing GE Software, Operating
30 Systems, and miscellaneous upgrades. The controller drops and rack-mounted
31 servers will not be replaced for this upgrade. (Standard practice is to replace
32 virtualized system hardware every eight years to reduce costs.) The DCS must
33 be upgraded at a four-to-five-year upgrade cycle to maintain reliable control
34 and recent operating systems and applications that are patchable. Vendor life
35 cycle for DCS versions is generally a five-year cycle. After five years they
36 enter a retired state and are no longer patched. Microsoft Operating Systems
37 (O/S) are on a limited life basis, and they reach the end of “extended support”
38 and no longer get security patches. Corporate policies require all systems to be
39 patched regularly along with Anti-Virus updates; and
- 40 • Fourteen additional projects at Jackson Plant totaling \$1.098 million, with each
41 individual project representing \$225,000 or less in expenditures. These projects
42 include (13476) JGS - LM1-6 Steam injection trap replacements, generator

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breaker replacements, breaker relay replacements, major motor and pump overhauls, and small valves, instrumentation, tools, equipment, pumps, and motors.

HYDRO UNITS

Q. Please explain the Company's projected capital expenditures for the 14-month projected bridge period ending February 28, 2025 and the projected test year ending February 28, 2026 for the Hydro Units.

A. The Company plans to invest \$42.376 million in the 14-month bridge period and \$92.258 million in the projected test year in the Hydro Units, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 3, line 64, columns (h) and (j), respectively.

Q. What is the basis for the projected \$42.376 million capital investment in the 14-month projected bridge period?

A. The projected \$42.376 million capital investment will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are ten projects which are greater than \$1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 20 through 29. The basis for these projects is described in the direct testimony of Company witness Monroe.

Q. What is the basis for the projected \$92.258 million capital investment in the projected test year?

A. The projected \$92.258 million capital investment in the projected test year will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are 13 projects which are greater than \$1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 21 through 33. The basis for these projects is described in the direct testimony of Company witness Monroe.

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LPS

Q. Please explain the Company's projected capital expenditures for the 14-month projected bridge period ending February 28, 2025 and the projected test year ending February 28, 2026 for the LPS.

A. The Company plans to invest \$10.279 million in the 14-month projected bridge period and \$15.587 million in the projected test year in the LPS, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 3, line 71, columns (h) and (j), respectively. These capital investments will be implemented in periodic outages in the spring of 2024 and 2025. It is important to note that none of these investments are associated with resolving the Toshiba defects. Those investments are being recorded to a regulatory asset pursuant to the MPSC's May 18, 2023 Order in Case No. U-21310.

Q. What is the basis for the projected \$10.279 million capital investment in the 14-month projected bridge period?

A. The projected \$10.279 million capital investment in the 14-month projected bridge period will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are two projects which are greater than \$1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 30-31. The basis for those projects is described below:

- Ludington Units 1 through 6 DCS Control Relay Replacement (\$1,648,169). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;
- LPS – Lower Penstock Expansion Joint (“LPEJ”) Chamber Waterstop replacement (\$2,716,000). The scope of this project is replacement of the LPEJ waterstop and potentially dewatering the surrounding groundwater. The engineering study was performed in 2020 at a cost of \$0.404 million and project

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1 implementation began in 2021 and is planned to be completed in 2024. In 2021,
2 the engineering was completed, and the design was approved by FERC; and

- 3 • The LPEJ Chambers enclose the penstock expansion joints in concrete
4 chambers. The penstock expansion joints allow penstock expansion with
5 seasonal temperature changes. The waterstop is a membrane intended to
6 prevent groundwater from leaking into the LPEJ. Some joints have been
7 leaking since shortly following plant construction. In February 2017, a
8 depression was discovered upstream of Ludington Unit 3, which was caused by
9 transport of soil into the chamber by inflowing groundwater. Historically,
10 Consumers Energy sealed the leaks into the LPEJs using hydrophobic
11 polyurethane grout. However, the waterstops are at the end of their expected
12 life and grouting is no longer an effective solution. Failure to remedy the in
13 leakage is a threat to generation because if the settlement of the chambers
14 reaches a certain threshold, the generation unit(s) will remain in a forced outage
15 until the LPEJ chamber(s) can be stabilized. The implementation of this project
16 reduces current risk of a potential failure mode and supports Ludington unit
17 generation well into the relicensing period.

18 The following projects are less than \$1 million but are important to regulatory compliance
19 and reliability:

- 20 • Replace Barrier Net Panels (\$679,115). This project spans the 14-month
21 projected bridge period and the projected test year, and its basis is included in
22 my discussion of the projected test year capital projects for Ludington;
- 23 • Replace 480V Dike Load Centers (\$993,800). This project spans the 14-month
24 projected bridge period and the projected test year, and its basis is included in
25 my discussion of the projected test year capital projects for Ludington;
- 26 • LPS Oil Water Separator Replacement (\$780,249). This project spans the
27 14-month projected bridge period and the projected test year, and its basis is
28 included in my discussion of the projected test year capital projects for
29 Ludington;
- 30 • LPS Intake Gate and Gate House Mechanical Replacement (\$409,099). This
31 project spans the 14-month projected bridge period and the projected test year,
32 and its basis is included in my discussion of the projected test year capital
33 projects for Ludington;
- 34 • Governor Replacement (\$474,167). This project spans the 14-month projected
35 bridge period and the projected test year, and its basis is included in my
36 discussion of the projected test year capital projects for Ludington;
- 37 • Ludington All Unit Critical Valve and Actuator Replacement (\$565,000). The
38 scope of this project is to replace valves, actuators, and associated equipment

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critical to unit specific operation. There are also certain valves that provide routine tagging points that provide worker protection. Many of these valves have known issues such as damaged seals (leakage when the valve is closed), leaking packing (cannot be tightened further), and severely corroded valve stem extensions. Additionally, many of these valves are paired with pneumatic actuators which have also been identified with operational issues. Most of the handwheels are broken and do not provide a secondary means of operating the valve if the pneumatic actuator were to fail. This could present a particularly dangerous situation if a pipe were to fail. Additionally, damage to the actuator linkages and slides have been noted in previous inspections. The linkage damage has introduced play or slop into the mechanism which can be seen during operation and will lead to eventual failure of the mechanism; and

- Twenty-two additional projects at LPS totaling \$2.014 million, with each individual project representing \$256,896 or less in expenditures. These projects include LPS DAC 1 and 2 replacement, subdrainage and unwatering sump pump controls and pump replacement, CO2 Fire Protection System Replacement Centralized Grease System Replacement, and small tools, pumps, motors, valves, and instrumentation.

Q. What is the basis for the projected \$15.587 million capital investment in the projected test year?

A. The projected \$15.587 million capital investment in the projected test year will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are five projects which are greater than \$1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 34 through 38. The basis for these projects is described below:

- DCS Control Relay Replacement (\$4,771,901). The scope of this project is to replace and eliminate worn and less reliable control relays with new electronic input/output modules and new relays where needed. The number of hardware control relays will be reduced due to the “control” being performed in logic instead of “hardwired” circuits. This will increase reliability and reduce outages and unit derates. Common control and monitoring of system equipment allows operation of the equipment from the Human Machine Interface (“HMI”) graphics and keeps the operator focused on one system instead of monitoring several systems from several areas of the control room.

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1 The LPS units are controlled by using the original hardwired
2 electromechanical relay control system to operate the units. A modern DCS
3 system will provide the LPS units with improved diagnostic and
4 troubleshooting capabilities. The DCS system will make it easier to automate
5 any updates of equipment and systems that are integrated with the unit
6 operation, and to implement, test, and verify changes to operating criteria.
7 Furthermore, the modern DCS has the capability to perform these functions at
8 a lower cost and requiring less time.

9 The existing relay control system is based on electromechanical devices that
10 wear and become less reliable over time. The relay contacts wear, and increased
11 resistance can cause intermittent failures. Troubleshooting these issues are
12 difficult and time-consuming. The relay control system will not last until end
13 of life of the units and need to be upgraded to a modern DCS control system.
14 The Emerson Ovation DCS infrastructure was installed as part of the 2019-2021
15 Data Acquisition System (“DAS”), Annunciator, PLC, and Sequence of Events
16 recorder replacement project. This provides a common historian, HMI graphics
17 control, alarm management system and modern control system for reliable
18 efficient unit operation. The DAS project provides the infrastructure to build
19 upon for full site/unit control at LPS;

- 20 • Replace 480V DLCs (\$1,566,400). The scope of this project is the replacement
21 of the 20 480V DLCs over a six-year period that began in 2020 at a capital
22 expenditure amount of \$0.671 million. The DLCs are original plant equipment
23 and suffer from corrosion and deterioration. The primary purpose of the DLCs
24 is to distribute power to 193 dike drain pumps and 34 pumping relief wells
25 located around the reservoir. The purpose of the dike drain pumps is to keep
26 the upstream face of the dike in a drained condition and to protect the asphalt
27 liner from damage due to differential pressure. The purpose of the pumping
28 relief wells is to keep groundwater at pre-construction levels, thereby
29 minimizing the likelihood of a downstream slope failure. Replacement of the
30 DLCs over a six-year period will provide high electrical system reliability and
31 ensure FERC compliance;
- 32 • LPS Commons Station Power Transformer (“SPT”) Life Cycle Management
33 (\$1,150,000). The scope of this project is to procure and replace all six SPTs
34 with new to suit size and configuration in current LPS footprint. The SPTs are
35 original to the site, and are in service outdoors on the LPS roof. The benefits
36 of the project are restoration of system voltage to rated, increase site equipment
37 life span, extension of life expectancy to that of site, enablement of the ability
38 to perform routine maintenance without risk of damage, and reduction in the
39 probability of failure and the associated risk of not having a spare;

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- Governor Replacement (\$1,915,833). The scope of this project is to contract with a specialized vendor to inspect, repair as required, and modernize the unit governors. The LPS unit governors have not been overhauled in approximately 15 years and, as a result, show signs of significant wear; and
- Intake Gate and Gate House Mechanical Replacement (\$1,666,014). The LPS intake gates and associated hoist equipment are the primary form of mechanical protection for the LPS units. Their purpose is to isolate the stored energy from the reservoir's water against each unit's penstock when dewatering or during emergency conditions such as a penstock rupture or governor failure. Reliable operation of this system is critical to minimize damages from a unit run away condition or a penstock failure, acting as a last effort to control unit overspeed. The mechanical system of the intake gate hoist is all original (circa 1971) and recent OEM inspection revealed that its condition is poor and in need of refurbishment. Updates and repairs are required to support the current facility license extension of 2069. The electrical control system is well past its design service life. This outdated technology is obsolete, and certain critical components are no longer available for spare parts. Modern technology offers more reliable options that would give the system an additional 30 years of service. The head gate hoist is enclosed in a steel structure on top of the intake (head gate enclosure). The head gate hoist enclosures are original to the plant and have rusted out in many places. Significant corrosion has been noted on the steel frame, the connections, and the beams. These enclosures need to be replaced as they are beyond a repair option.

The following projects are less than \$1 million but are important to regulatory compliance and reliability:

- LPS Oil Water Separator ("OWS") Replacement (\$438,746). The scope of work for this project is to install a separate, parallel train OWS to that of the plant's existing OWS, modify existing support systems (station sump, station sump pumps, and metering devices) to support new OWS, and retrofit the existing OWS to improve oil separability. This will allow temporary use of the modified original OWS while servicing the anticipated new one as to not impact unit availability. The project is being performed in order to comply with requirements for effluent discharge during all modes of operation and process upset conditions. The failure to perform this project would likely lead to additional releases in excess of the National Pollutant Discharge Elimination System permit requirements throughout the facility's lifecycle. Although not quantified, cost for these releases could be significant in terms of potential fines, reputational damage, cleanup costs, and other intangibles;
- Centralized Grease System Replacement (\$303,604). The scope of this project is to replace end of service life components such as pumps, distributing blocks, and solenoid valves, and to modernize the control system to a self-diagnostic

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PLC system. The current electro-pneumatic grease system(s) that service certain bushings are past their service life and of questionable reliability (original plant functionally equipment);

- Replace Barrier Net Panels (\$829,725). The panels are a regulatory required system to minimize fish entrainment. The panel replacements are primarily time based. LPS has extensive operating experience with these panels, which helps determine when a replacement is required; and
- Nineteen additional projects at Ludington totaling \$2.944 million, with each individual project representing \$298,332 or less in capital expenditures. These projects include north fabrication shop storage mezzanine and humidity control, pony motor isolation switch life cycle project, all unit critical valve and actuator replacement, cathodic protection system replacement, main transformer bank isophase cooling blower replacement, subdrainage and unwatering sump pump controls and pump replacement, flow transmitter replacement, and small tools, pumps, motors, valves, and instrumentation.

ADMINISTRATIVE AND OTHER

Q. Please explain the Company's projected capital expenditures for the 14-month projected bridge period ending February 28, 2025 and the projected test year ending February 28, 2026 for Administrative and Other.

A. The Company plans to invest \$2.795 million in the 14-month projected bridge period and \$3.096 million in the projected test year in Administrative and Other, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 3, line 78, columns (h) and (j), respectively.

Q. What is the basis for the projected \$2.795 million capital investment in the 14-month projected bridge period for Administrative and Other?

A. The projected \$2.795 million capital investment will support several projects during the 14-month bridge period. The basis for these projects is described below:

- Generation Operations – Ovation security center replacement evergreen (\$300,000). The Generation control systems cyber security tool that is used for control system security is the Emerson PWCS. This tool is comprised of multiple cyber security products used in the industry today. Because of the quickly changing technology and techniques used by hackers, the cyber security tools require an increased update cycle of two to three years. The Karn site has been using the PWCS tool for 10 years. It was last upgraded in 2017. To

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support the latest version of Ovation DCS, the PWCS system must be upgraded. This replacement will support the protection of multiple components of the control system across multiple sites including Karn Units 3 and 4, Campbell, Jackson, Zeeland, and Ludington. The tools included are:

- Anti-Virus;
- Malware Prevention with Application Control;
- Patch Management;
- Device Control;
- Rogue System Detection;
- System Backup and Recovery;
- Security Incident and Event Manager; and
- Change Management.

- Fleet - Move the machine shop (\$616,667). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Administrative and Other;

- Transformation - Enterprise Project Management Information System (\$850,010). The scope of this project is the continuing support of Unifier, the Company's project management information system ("PMIS"). During the bridge period, the Company is implementing a major upgrade to Unifier and Primavera P6 ("P6"). Specifically, the Company is moving from version 19.12 to 22.12 for both Unifier and P6. The upgrade reflects three years of upgrades from oracle which includes various enhancements. The scope of the project also includes the February 2024 procurement of 350 additional licenses to support the continued user growth the Company expects from the new functionality in the upgrade. The increased user growth includes expansion of the products to additional engineering personnel, some project management personnel, and some vendors. In addition to the upgrade and procurement of additional licenses, the Company has continued its quarterly implementation of continuous-improvement updates (new functionality that Company users identify) that include the creation and or configuration of new reporting and business processes; and

- Seven additional projects totaling \$1.028 for generation cyber security, ovation cyber security, laptop and capital business tool purchases for Generation Engineering, Electric Supply, Environmental Services, Lab Services, Business Services, and Enterprise Project Management.

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1 **Q. What is the basis for the projected \$3.096 million capital investment in the projected**
2 **test year?**

3 A. The projected \$3.096 million capital investment in the projected test year will fund various
4 projects. One of these projects is greater than \$1 million, and is presented on Exhibit A-12
5 (RTB-3), Schedule B-5.2, page 9, line 20. The basis for these projects is described below:

- 6 • Fleet - Move the machine shop (\$2,100,000). The scope of this project is to
7 move the machine shop. The existing machine shop is located at the Campbell
8 site and with the closure of the Campbell units on May 31, 2025, the Company
9 will likely have to relocate the existing machine shop. Options for the project
10 include (1) doing nothing and going to third parties for parts which will impact
11 both cost and timing of delivery, (2) purchasing another machine shop,
12 (3) section off the training center at Campbell and move the machine shop to
13 that building, and (4) Building a machine shop in a centralized location to better
14 service all generation sites.

15 The machine shop has proven its financial viability, with a positive variance
16 of \$67,978 in 2023. It has consistently demonstrated the ability to generate
17 revenue exceeding operational costs, a trend expected to continue based on
18 projections. The shop's ability to quickly turn around projects and fabricate
19 parts faster than external vendors has led to substantial savings, particularly in
20 replacement power costs, estimated at \$300k annually; and

- 21 • Eight additional projects for generation cyber security, laptop and capital
22 business tool purchases for Generation Engineering, Electric Supply,
23 Environmental Services, Lab Services, Business Services, and Enterprise
24 Project Management (\$996,250).

25 **COMPANY-OWNED SOLAR RESOURCES**

26 **Q. Please explain the Company's projected capital expenditures for the 14-month**
27 **projected bridge period ending February 28, 2025 and the projected test year ending**
28 **February 28, 2026 for Company-owned solar resources.**

29 A. The Company plans to invest \$249.572 million in the 14-month projected bridge period
30 and \$275.959 million in the projected test year in Company-owned solar resources, as

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1 shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 50, columns (h) and (j),
2 respectively.

3 **Q. What is the basis for the projected \$249.572 million capital investment in the**
4 **14-month projected bridge period?**

5 A. The projected \$249.572 million capital investment in the 14-month projected bridge period
6 will fund the IRP-approved solar generation development. This entire investment amount
7 is reflected in two separate projects, Muskegon Solar and Spring Creek, which are each
8 greater than \$1 million and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2,
9 page 8, lines 32 and 33. The basis for these projects is described in the direct testimony of
10 Company witness Clark.

11 **Q. What is the basis for the projected \$275.959 million capital investment in the**
12 **projected test year?**

13 A. The projected \$275.959 million capital investment in the projected test year will fund the
14 IRP-approved solar generation development. This entire investment amount is reflected in
15 three separate projects, Muskegon Solar, Washtenaw, and Spring Creek, which are each
16 greater than \$1 million and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2,
17 page 9, lines 39 through 41. The basis for those projects is described in the direct testimony
18 of Company witness Clark.

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BATTERY ENERGY STORAGE SYSTEMS

Q. Please explain the Company's projected capital expenditures for the 14-month projected bridge period ending February 28, 2025 and the projected test year ending February 28, 2026 for BESS.

A. The Company plans to invest \$39.672 million in the 14-month projected bridge period and \$78.921 million in the projected test year in Company-owned battery resources, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 3, line 85, columns (h) and (j), respectively.

Q. What is the basis for the projected \$39.672 million capital investment in the 14-month projected bridge period?

A. The projected \$39.672 million capital investment in the 14-month projected bridge period will fund BESS. This entire investment amount is reflected in three separate projects, Armstrong, Iosco, and Weadock, which are each greater than \$1 million and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 34 through 36. The basis for these projects is described in the direct testimony of Company witness Clark.

Q. What is the basis for the projected \$78.921 million capital investment in the projected test year?

A. The projected \$78.921 million capital investment in the projected test year will fund the BESS. This entire investment amount is reflected in three separate projects, Armstrong, Iosco, and Weadock, which are each greater than \$1 million and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 42 through 44. The basis for those projects is described in the direct testimony of Company witness Clark.

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1 **Q. Are you supporting any other projected capital expenditures for generation related**
2 **projects in the test year ending February 28, 2026?**

3 A. Yes. I am also supporting an IT project, Generation Operations Digital Work Management.
4 The test year projected capital expenditure amount is \$713,873, and the test year projected
5 O&M expense amount is \$54,383. These amounts are reflected in the exhibits of Company
6 witness Shivaji Kandan. The scope of the project includes: the initial roll out for Electric
7 Generation at Ludington, and Renewable Generation, which would include: (1) purchase
8 of mobile field devices for Ludington, (2) purchase of additional mobile work management
9 software licenses, (3) development and configuration of forms and workflow for these
10 groups, and (4) enhancement of the wireless connection at Ludington.

11 **Q. What are the benefits of this technology project?**

12 A. This project provides the following value to the Company: (1) Productivity is improved,
13 and human struggle reduced by simplification of work tracking through the mobile
14 software. Time sheet charging is incorporated to the work order when someone on the
15 crew pushes the clock to start versus being separately entered through SAP Employee Self
16 Service. If there is more than one person on a crew, information is entered for the full crew
17 versus individually, including time tracking. Functionality is available to more easily
18 create a digital punch list in the field when a worker sees something instead of later writing
19 it on a punchboard and entering it separately into SAP; (2) Employee Engagement
20 improves as the more tech savvy candidate pool for these positions are looking for mobile
21 software to help them do their jobs; (3) Quality is improved by creating a digital punch list
22 when the technicians find an issue versus manually documenting it later. Accuracy
23 increases and rework decreases when updates are performed right at the time and place of

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1 the work instead of afterwards. Productivity can also be tracked and measured for further
2 improvements. This level of tracking is not possible with the current process and
3 information; (4) Safety is improved as employees have remote access to manuals to
4 reference before moving forward with and during their work. The access to manuals
5 increases productivity and better supports error reduction training by having the manuals
6 available so a worker can move beyond “I think” and “I believe.” The project will mitigate
7 the risk of work and safety errors from using outdated procedures; (5) For Renewable
8 Generation, the improved maintenance program will reduce equipment downtime resulting
9 in an increase to Megawatt hours produced; and (6) For Ludington, the new mobile devices
10 will allow working with electronic Systems Operations Management System (“eSOMS”)
11 which will improve productivity and reduce non-premise time.

12 **Q. Did the Company consider alternatives for this project?**

13 A. Yes. The alternatives considered include: (1) Utilizing an SAP work management mobile
14 solution. An SAP work management solution is not preferred since it is a new solution and
15 requires additional project and support cost; (2) Continuing the manual paper-based
16 process. Continuing the manual paper-based process was not chosen because of process
17 waste, re-work, and human error; (3) Customizing the existing electronic eSOMS mobile
18 application to add work management functions. A custom eSOMS mobile application was
19 not chosen because it would require additional project cost and an ongoing support budget
20 for a custom solution that the eSOMS product was not intended to support; and (4) Utilizing
21 an out-of-the-box solution to minimize cost and risk to the Company and its employees.
22 The combined Service Suite and digital form solution is the preferred option because it is

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1 a proven solution and provides the mobility and digital benefits at a lower cost than other
2 alternatives.

3 **GENERATION CAPITAL EXPENDITURES—SUMMARY**

4 **Q. Are the Company's capital expenditures in power generation reasonable and**
5 **prudent?**

6 A. Yes. As discussed, the proposed capital expenditures are directly aligned with the
7 Company's generation asset strategy and, as a result, will provide economic value for
8 power supply customers in the energy and resource adequacy markets. Other capital
9 expenditures in generation are related to regulatory and environmental compliance, and
10 thus are not discretionary. Company witnesses Clark and Monroe provide additional
11 discussion in their direct testimony.

12 **SECTION IV**

13 **GENERATION O&M EXPENSE**

14 **Q. What are the major drivers in determining the O&M expense levels you are**
15 **sponsoring in this proceeding?**

16 A. The major drivers are identifying the funding needed to support the daily operation and
17 maintenance of the Company's fleet of generating facilities and identifying the funding
18 needed for certain internal organizations that support Generation Operations.

19 **Q. For purposes of your direct testimony in this case, what does the Generation O&M**
20 **cost represent?**

21 A. In addition to the Company's generation fleet, I am sponsoring the O&M expenses for the
22 Electric Supply Operations and PSCR organization, Electric Regulation and Strategy
23 Implementation organization, Financial Planning organization, Renewable Energy

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Department, Contracts and Settlements organization, Generation Asset Management organization, Electric Sourcing and Resource Planning organization, and Enterprise Project Management and Environmental Services organization.

Q. Please describe Exhibit A-43 (RTB-4), page 1, Generation Operation and Maintenance Expenses.

A. Exhibit A-43 (RTB-4), page 1, identifies the actual 2023 through 12 Months Ending February 28, 2026 projected Generation O&M expenses. Specifically:

- Column (a) identifies each O&M expense category;
- Column (b) identifies the Actual 2023 Generation O&M expense as \$118,848,652;
- Column (c) identifies the 14-Month Projected Bridge Period Generation O&M expense as \$165,164,491; and
- Column (d) identifies the Projected Test Year Generation O&M expense as \$111,850,689.

HISTORICAL O&M EXPENSE

Q. How does Consumers Energy determine the level of Generation O&M spending?

A. Consumers Energy tracks the history and projects future maintenance needs of each generating unit. Personnel at the plants provide information on maintenance for each site or specific units. Once costs to operate and comply with regulations are prioritized, the Asset Strategy and Generation Planning organizations evaluate the plans required to maintain and/or improve the condition of the plant – weighing the estimated benefit to the customer for each project. Using this combination of information, a preliminary plan is prepared and reviewed to ensure high-priority issues are addressed and adequate resources and funding are available. After all appropriate levels of management have reviewed and

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1 approved the maintenance plan, a schedule is created. The overall objective is the safe,
2 reliable, and cost-effective generation of electricity.

3 **Q. How are Generation O&M expenses categorized?**

4 A. Generation O&M expenses are categorized into four primary components – “Base,”
5 “Environmental Operations,” “Major Maintenance,” and “Retention and Separation.”

6 **Q. What are Base O&M expenses?**

7 A. Base O&M expenses are comprised of two categories – labor and non-labor. Labor is the
8 primary component and typically has a predictable, stable rate of increase. Because most
9 of the Company’s generating units have been in service for years, the Company has an
10 excellent basis upon which to make accurate forecasts. Non-labor expenses also tend to
11 increase at a predictable rate and include items required to operate the plants. These items
12 include but are not limited to: (1) fuel (diesel and gasoline) for equipment and vehicles;
13 (2) material; (3) tools; (4) cleaning supplies; (5) facilities; (6) security; and (7) road and
14 grounds maintenance.

15 **Q. Please explain how the 2023 Actual O&M expenses were developed.**

16 A. The 2023 Actual O&M expenses were taken from Consumers Energy’s internal accounting
17 records.

18 **Q. Please explain how the 14-month projected bridge period and projected test year Base**
19 **O&M expenses were determined.**

20 A. Base O&M expenses for the projected bridge period ending February 28, 2025, and
21 projected test year ending February 28, 2026 shown on Exhibit A-43 (RTB-4), page 1,
22 line 1, columns (c) and (d), were determined by considering staffing levels and historical
23 spending. Total O&M expense for the years 2023 through the projected test year

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1 demonstrates average annual decreases of approximately 2.7%. As discussed later in this
2 direct testimony, this average annual decrease reflects a change in the mix of the
3 Company's owned generating assets as well as focused cost reductions. Exhibit A-43
4 (RTB-4), page 1, lines 3 and 4, identify Adjusted O&M expenses which are new or
5 projected to change from past years' expense levels. These include items that are required
6 by law to maintain environmental compliance, for the safety of employees, and to support
7 the reliability of service to customers, specifically, Environmental Operations and Major
8 Maintenance. Exhibit A-43 (RTB-4), page 1, line 5, identifies Adjusted O&M expenses
9 which are related to Retention and Separation expenses associated with the Karn and
10 Campbell sites. These expenses were required for the safe and reliable operation of Karn
11 Units 1 and 2 through their May 2023 retirement and are required for the continued safe
12 and reliable operation of Campbell Units 1, 2, and 3 through their May 2025 retirement.

13 **Q. How do the historical and projected test year O&M expense amounts compare to**
14 **prior years?**

15 A. The 2023 historical O&M expense amount of \$118.849 million and the projected test year
16 O&M expense amount of \$111.851 million compare quite favorably to the actual O&M
17 expense amounts for 2021 and 2022. The 2021 generation O&M expense amount was
18 \$155.204 million, and the 2022 generation O&M expense amount was \$150.031 million.
19 As I previously stated, the O&M expense reductions reflect a mix of generation asset
20 changes as well as other focused cost reductions.

21 **Q. Please explain Exhibit A-43 (RTB-4), page 2.**

22 A. Exhibit A-43 (RTB-4), page 2, presents the amounts of the projected O&M expenses that
23 were developed by applying either an inflation rate or contract rate to historical O&M

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1 expense. Column (b) presents the historical O&M expense. Column (c) presents the
2 amount of the historical O&M amount to which an inflation rate or contract rate applies.
3 Columns (e) and (g) present the amounts to which an inflation rate or contract rate were
4 applied for each period, respectively. Columns (d), (f), and (h) present contract and
5 inflation increases for each respective period. Amounts that were projected using other
6 methods are included in column (i). Column (j) is the projected test year O&M and is the
7 sum of columns (b), (d), (f), (h), and (i).

8 **Q. Please explain how the various inflation and contract rates were applied to Labor,**
9 **Material, Contractor, and Non-Labor Other O&M expense on Exhibit A-43 (RTB-4),**
10 **page 2.**

11 A. The historical labor on line 1, column (b) reflects a combination of both Operating
12 Maintenance and Construction ("OM&C") and non-represented labor. Inflation rates of
13 2.4%, 2.2%, and 2.2% were applied to labor on line 1, material on line 2, contractor on
14 line 3, and non-labor other on line 4 to develop the annual increase amounts in columns (d),
15 (f), and (h).

16 **Q. Please discuss how the adjustments on Exhibit A-43 (RTB-4), page 2, column (i) were**
17 **determined.**

18 A. As previously discussed, the Company projects the future maintenance needs of each unit.
19 The test period projected O&M expense amount of \$111.851 million reflects that
20 evaluation. Within the test period projected amount of \$111.851 million, there are several
21 adjustments that result in a projected amount that differs from the amount that is calculated
22 based solely on inflation.

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1 **Q. Please discuss the adjustments that are reflected in the test year projected amount of**
2 **\$111.851 million.**

3 A. As previously discussed, the Settlement Agreement reached in the Company's 2018 IRP
4 reflects the retirement of Karn Units 1 and 2 on May 31, 2023 and the Settlement
5 Agreement reached in the 2021 IRP reflects the retirement of Campbell Units 1, 2, and 3
6 on May 31, 2025 and the addition of Covert Units 1, 2 and 3 on June 1, 2023.

7 **Q. Please discuss the decrease in O&M expense for Karn Units 1 and 2.**

8 A. The 2023 O&M expense for Karn reflects the fact that Karn Units 1 and 2 retired on
9 May 31, 2023, leaving only Karn Units 3 and 4 operational. The actual O&M expense for
10 the Karn site in 2023 was \$19.091 million versus the projected O&M for the test year at
11 \$13.106 million, with the biggest decrease reflected in base O&M. The 2023 environmental
12 operations expense for the Karn site was \$2.254 million and that has been reduced to
13 \$0.093 million in the projected test year. The 2023 base O&M expense was \$16.554
14 million whereas the projected test year base O&M drops to \$10.411 million. The Karn
15 major maintenance expense increases from \$0.283 million in 2023 to \$2.602 million in the
16 projected test year. This increase reflects the fact that the Company limited the amount of
17 major maintenance it planned for Karn Units 3 and 4 in 2023 since its 2021 IRP proposed
18 the coincident retirement of those units with Karn Units 1 and 2. When the 2021 IRP
19 settlement did not include Karn Units 3 and 4 retiring early, the Company needed to
20 perform the deferred major maintenance. A complete discussion of the test year major
21 maintenance for Karn Units 3 and 4 is described later in this direct testimony.

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1 **Q. Please discuss the decrease in O&M expense for Campbell Units 1, 2 and 3.**

2 A. The projected test year O&M expense for Campbell reflects the fact that the Campbell units
3 will only operate for three months, March through May 2025. The projected test year
4 expense for Campbell is \$13.935 million, a \$29.392 million reduction from the actual 2023
5 O&M expense of \$43.327 million. The biggest reduction from the historical year to the
6 projected test year is reflected in base O&M expense. The base O&M expense in the
7 projected test year is \$11.204 million, a \$23.653 million reduction from the historical
8 expense of \$34.858 million. The 2023 environmental operations expense for Campbell
9 was \$6.421 million and that has been reduced to \$2.186 million in the projected test year.
10 The Campbell major maintenance expense decreases from \$2.049 million in 2023 to only
11 \$0.545 million in the projected test year. A complete discussion of the test year major
12 maintenance for Karn Units 3 and 4 is described later in this direct testimony.

13 **Q. Please discuss the increase in O&M expense for Covert Units 1, 2, and 3.**

14 A. The 2023 O&M expense for Covert reflects the fact that the Company didn't take
15 ownership of the plant until June 1, 2023. The actual O&M expense for Covert Units 1, 2
16 and 3 in 2023 was \$7.413 million for the period from June 1, 2023 through December 31,
17 2023. The projected O&M for the test year is \$16.873 million, with the biggest increase
18 reflected in major maintenance. The 2023 expense for major maintenance was
19 \$2.144 million however it is project to total \$7.706 million in the test year. A complete
20 discussion of the test year major maintenance for Covert is described later in this direct
21 testimony. The 2023 environmental operations expense for Covert was \$0.072 million and
22 that expense is slightly lower at \$0.053 million in the projected test year. The base O&M

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reflects an increase from \$5.196 million for the period from June 1, 2023 through December 31, 2023, to \$9.114 million in the test year.

Q. Are these generation asset changes the only reasons for the reduced O&M expense?

A. No. As I previously indicated, the Company has implemented other focused cost reductions that have directly impacted both the actual 2023 O&M expense and the projected test year expense. These cost reductions are primarily represented by headcount reductions during 2023 which have reduced both capital expenditures and O&M expense.

Q. Did the Company implement any projects that exclusively impacted capital expenditures?

A. Yes. The Company has implemented an improved governance process and key performance management metrics that will allow it to improve the efficiency of its capital expenditures. While the Company will not necessarily reduce its overall capital expenditures, it does expect that it will be able to accomplish more work with the same amount of capital.

Q. Did the Company implement any generation capital projects which reduce other customer costs?

A. Yes. The Company implemented a project at Jackson for the HRSG Burner Element Isolation Valves Addition (see Exhibit A-12 (RTB-3), Schedule B-5.2, page 7, line 9) in 2023 that will reduce both O&M and PSCR expense. The project involved the addition of automated low point drain and vent on each gas manifold, the addition of isolation valves on all burner elements, and burner management system ("BMS") logic changes to control drains and vents. The benefits of the project are the mitigation of condensation in burner piping and elements which leads to ignition failure, burner tube failure, and flame

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1 impingement which would eventually lead to burner elements replacements because of
2 those issues. In addition, the project will increase generation production or capability due
3 to less duct burner down time because of the ability to isolate individual duct burners rather
4 than an entire HRSG. The increased generation production or capability is intended to
5 result in a reduction of PSCR costs, and the improved reliability of the burner elements
6 will result in reduced O&M expense.

7 **ENVIRONMENTAL OPERATIONS**

8 **Q. What are Environmental Operations expenses?**

9 A. Environmental Operations expenses consist of labor and materials supporting the
10 operations of the Company's AQCS. As Federal and State emissions standards require
11 cleaner air, Consumers Energy has installed AQCS to comply with these regulations.
12 Consumers Energy deployed its full suite of AQCS devices in 2016, with 2017 being the
13 first calendar year of operation. Now that the Company has experienced multiple calendar
14 years of operation, the Company anticipates these expenses to remain relatively consistent
15 going forward. However, because the cost to operate and maintain these critical pieces of
16 equipment is directly related to the operation of the coal-fired power plants they support,
17 yearly variances in the total Environmental Operations expense should be expected based
18 on the operation of the coal plants in a given year.

19 **Q. Please explain how the projected Environmental Operations expenses for the**
20 **projected bridge period ending February 28, 2025 and test year ending February 28,**
21 **2026 were calculated.**

22 A. Environmental Operations expenses are a combination of O&M costs related to the
23 environmental equipment at the Karn and Campbell sites. The operations component is

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1 primarily calculated using labor costs for operations and environmental waste disposal.
2 The maintenance component is based on a combination of historical and estimated planned
3 maintenance costs on the specific components of environmental equipment. 2023 was the
4 seventh full year of operations of the environmental equipment at both Campbell and Karn,
5 and the Company now has robust historical data to use in projecting these expenses.
6 However, as reflected on Exhibit A-43 (RTB-4), page 1, line 3, columns (b) and (d), the
7 walk from the 2023 historical expense of \$9.225 million to the projected test year expense
8 of \$2.584 million reflects a cost reduction of \$6.641 million despite inflationary increases.
9 This cost reduction is a direct reflection of the retirement of Karn Units 1 and 2 on May 31,
10 2023 and the retirement of Campbell Units 1, 2 and 3 on May 31, 2025.

11 **MAJOR MAINTENANCE**

12 **Q. What are Major Maintenance expenses?**

13 A. Major Maintenance represents O&M projects that are based on asset condition or on
14 historic maintenance intervals over multiple years. To maintain and improve the
15 performance of generating fleet, the Company performs Major Maintenance on a regular
16 basis. However, completion of Major Maintenance work can be influenced by, among
17 other things, actual operations of the generating units, availability of parts and labor, and
18 energy market conditions.

19 **Q. Please explain how the Major Maintenance O&M expenses for the projected bridge**
20 **period ending February 28, 2025 and test year ending February 28, 2026 were**
21 **determined.**

22 A. Major Maintenance expenses are determined by tracking both the historical and future
23 maintenance needs for each site and unit, considering operation safety, unit reliability, and

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1 maximum customer value. Individual projects are calculated in a manner similar to capital
2 projects, as discussed earlier in this direct testimony.

3 **Q. Please identify the 2023 test year Major Maintenance O&M expenses.**

4 A. The Company projects that it will incur \$31.203 million in Major Maintenance O&M
5 expenses during the test year, as identified by Exhibit A-43 (RTB-4), page 1, line 4,
6 column (d). Test year Major Maintenance expense by generating unit is presented on
7 Exhibit A-43 (RTB-4), page 3, column (d).

8 **Q. Why is Consumers Energy spending \$31.203 million in Total Major Maintenance**
9 **O&M expense during the projected test year ending February 28, 2026?**

10 A. The Company is spending the majority of its Total Major Maintenance expense during the
11 test year to maintain reliability. Reliability related Major Maintenance O&M expenses,
12 made predominantly during scheduled outages, allow the plants to avoid equipment issues
13 that would lead to more frequent random outages, exposing customers to potentially more
14 expensive replacement energy at market prices. Minimizing forced outages by maintaining
15 equipment improves the likelihood the unit will be available when needed and minimizing
16 damage that could result in the event of a catastrophic failure.

17 **Q. Are Major Maintenance expenses relatively consistent from year to year?**

18 A. No. Although the Company attempts to plan for controlled and consistent levels of Major
19 Maintenance, because Major Maintenance outages occur relatively infrequently, for an
20 individual unit, it is very possible to have significant year-by-year variations in the number,
21 duration, and magnitude of the required Major Maintenance work. Other factors such as
22 unforeseen equipment failure, emerging industry initiatives, unit dispatch, expected power

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1 prices, unit performance, and simple timing variations can impact the cost and scheduling
2 of Major Maintenance.

3 **Q. Is it possible that changes to the Company's forecasted Major Maintenance plan**
4 **could occur?**

5 A. Yes. It is possible that the Company's forecasted Major Maintenance plan could change.
6 Equipment condition can change such that the timing of maintenance activities may need
7 to be accelerated or delayed. The Company attempts to make the best decision in balancing
8 the cost and risks associated with the operation of the equipment and attempts to minimize
9 the cost to customers. Factors such as weather, equipment and labor availability, energy
10 market conditions, and electrical system stability considerations can affect the actual
11 timing of an outage and maintenance spending.

12 **Q. Do Major Maintenance costs vary by individual generating unit(s)?**

13 A. Yes. As the Company's generating units vary in age, size, type, and design, so do the costs
14 to maintain these units. As an example, Major Maintenance of Campbell Unit 3 coal
15 pulverizers (785 MW) would be considerably larger in scope and cost than Major
16 Maintenance of Campbell Unit 1 coal pulverizers (260 MW), which is located on the same
17 site.

18 **Q. Is it common for an electric utility to have different sizes, types, designs, and dispatch**
19 **of generating units in its generation portfolio?**

20 A. Yes. Consumers Energy is not unique in that its fleet contains units of different size, type,
21 and design.

22 **Q. What are the categories of Major Maintenance?**

23 A. Major Maintenance is broken into two categories—outage and non-outage.

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1 **Q. Please describe what is included in the outage major maintenance O&M expense.**

2 A. Outage major maintenance O&M expenses are those associated with major overhauls and
3 require that the generating unit be removed from service for boiler and/or turbine
4 inspections and maintenance. These outages are typically scheduled on a periodic basis
5 and are required by law, insurance providers, and/or industry standards to ensure
6 operational safety and reliability. One example of a major maintenance outage is the
7 periodic disassembly and repair of turbine control and stop valves. The valves control the
8 amount of steam going to the turbine and are needed to control the unit output. During an
9 emergency situation, for example during unit electrical trip, the valves must react very
10 quickly to stop the steam going to the turbine to prevent it from overspeeding.
11 Overspeeding the turbine can result in severe mechanical damage resulting in a very long
12 duration outage to repair, further resulting in increased cost to customers for market priced
13 electricity during the outage. Periodic maintenance of turbine valves is required for
14 personnel and equipment safety. Maintaining the valves on a periodic basis ensures that
15 the clearances and internal components operate as designed and can reliably stop the
16 turbine quickly when needed to prevent turbine or generator damage.

17 **Q. Please describe the work completed in a boiler inspection.**

18 A. Boiler inspections assess the fire (outside) and steam (inside) sides of boiler tubing for
19 weaknesses that will ultimately result in water/steam leaks. After the boiler has been
20 properly opened, ventilated, and cleaned, scaffolding is constructed inside the boiler to
21 provide access to the boiler tubes. Inspections are completed using a number of different
22 methods – visual, non-destructive, and destructive. Visual and non-destructive testing are
23 the most common methods of inspection. Non-destructive testing incorporates the use of

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1 ultrasonic, x-ray, magnetic particle, or like technologies to measure pipe wall thickness.
2 Boiler tubes that are in poor condition or exceed minimum wall thickness are repaired or
3 replaced. After all repairs are complete, boiler tubes are pressure tested. Each boiler is
4 inspected on a specific time schedule, with a one-, two-, or three-year maximum interval.
5 Internal components with known problems are inspected more frequently. External
6 inspections are performed daily by Generation Operations and annually by state inspectors.

7 **Q. Please describe the work completed in a turbine inspection.**

8 A. Turbine inspections consist of disassembling, inspecting, and cleaning the different
9 components of the turbine. During the inspection, worn or damaged parts are repaired or
10 replaced to specific tolerances. Because of the extreme conditions under which these units
11 operate, the demand for uninterrupted power, and dangers associated with operating these
12 large pieces of equipment, industry standards recommend that inspections be completed
13 every seven years.

14 **Q. Please define non-outage maintenance.**

15 A. Non-outage maintenance O&M costs typically do not require the generating unit be
16 removed from service, but they are still critical to the operation of the unit. An example of
17 non-outage maintenance is Mill/Pulverizer maintenance.

18 **Campbell Units 1 and 2 Major Maintenance**

19 **Q. Please describe Campbell Units 1 and 2 Major Maintenance expenses for the**
20 **projected test year ending February 28, 2026.**

21 A. As shown on Exhibit A-43 (RTB-4), page 3, line 1, column (d), Campbell Units 1 and 2
22 Major Maintenance expense is forecasted to be \$0.268 million in the projected test year
23 ending February 28, 2026, and includes:

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- Campbell Units 1 and 2 Periodic Outage Major Maintenance (\$60,000). The scope of this project is to perform boiler maintenance activities during outages during the projected test year. Expenses include planning, engineering services, materials, and overtime labor;
- Campbell Unit 1 Pulverizer Maintenance (\$60,000). The scope of this project is the procurement of required parts to support the on-going maintenance of the coal pulverizers to maintain their operability. This maintenance work will allow the Company to keep the minimum number of mills in service and, as a result, avoid unit derates due to degraded conditions. The performance of this work will result in safe, reliable, and efficient unit operation;
- Campbell Unit 2 Mill Maintenance — Parts Only Boiler Plant Equipment (\$60,000). The scope of this project is the procurement of required parts to support the on-going maintenance on the coal mill/pulverizers to maintain their operability. This maintenance work will allow the Company to keep the minimum number of mills in service and, as a result, avoid unit derates due to degraded conditions. The performance of this work will result in safe, reliable, and efficient unit operation; and
- One project common to Campbell Units 1 and 2 totaling \$30,010 and two Site Common Major Maintenance projects totaling \$135,577 which are shared with Campbell Unit 3. Campbell Units 1 and 2 receive a 43% allocation totaling \$58,298 and Campbell Unit 3 receives a 57% allocation or \$77,279. These projects, all of which represent \$92,377 or less in expense, include fuel handling dumper outage repairs, deepwater intake screen inspection, and SDA O&M costs.

Campbell Unit 3 Major Maintenance

Q. Please describe Campbell Unit 3 Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 2, column (d), Campbell Unit 3 Major Maintenance expense is forecasted to be \$0.277 million in the test year and includes:

- Campbell Unit 3 Pulverizer Maintenance — Parts Only Mills-Boiler Plant Equipment (\$60,000). The scope of this project is the procurement of required parts to support the on-going maintenance on the coal pulverizers to maintain their operability. This maintenance work will allow the Company to keep the minimum number of mills in service and, as a result, avoid unit derates due to degraded conditions. The performance of this work will result in safe, reliable, and efficient unit operation;

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- Campbell Unit 3 Periodic Outage Major Maintenance (\$94,384). The scope of this project is to perform boiler, turbine, and BOP maintenance activities during outages during the project test year. Expenses include planning, engineering services, materials, and overtime labor. Performance of this work will result in improved unit reliability and performance; and
- One other Campbell Unit 3 project totaling \$45,000 and two Site Commons projects that I discussed previously with the Campbell Unit 3 allocation totaling \$77,279.

Karn Units 1 and 2 Major Maintenance

Q. Please describe Karn Units 1 and 2 Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 3, column (d), Karn Units 1 and 2 Major Maintenance expense is forecasted to be \$0.100 million in the projected test year ending February 28, 2026. This forecasted expense for the projected test year ending February 28, 2026 is for vegetation removal.

Covert Plant Major Maintenance

Q. Please describe the Covert Plant Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 8, column (d), the Covert Plant Major Maintenance expense is forecasted to be \$7.706 million in the projected test year ending February 28, 2026, and includes:

- Covert Plant LTSA Major Maintenance (\$2,611,312). This is the major maintenance portion of the Mitsubishi negotiated services that cover the planned normal maintenance of each generating unit. The projected major maintenance expenses are based upon variable fees paid to Mitsubishi for maintenance services which are based on an effective fired hours basis pursuant to the LTSA. Unlike the GE LTSAs for the Jackson and Zeeland plants, there are no milestone payments associated with the fee structure for the Mitsubishi LTSA. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected pre-mature failures of the equipment. This will help maximize availability and,

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as a result, optimize customer value for the site. Normal maintenance will ensure the Company continues reliable operation of the units;

- Covert Plant LTSA extra work Major Maintenance (\$1,492,500). This is the major maintenance portion of the Mitsubishi negotiated services that are not covered in the planned normal maintenance of each generating unit. Based on historical outage experience, there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items not covered under the LTSA that need to be addressed are labor and material to replace the following: blading, ammonia delivery system, SCR catalyst, turbine rotors, cooling towers, and turbine cooling air cooler;
- Covert Plant Capacity Factor Used For Water and Chemicals (\$1,216,667). This item provides for the city water used by the Covert Plant, and for the chemicals required to operate the water purification systems that are used to purify the makeup water prior to use;
- Reverse Osmosis System (“RO”), operation agreement (\$461,667). The scope of this project is to contract with a third party to operate and maintain the RO system;
- Covert Plant Base Outage Funding – Boiler plant equipment (\$483,333). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages;
- Covert Plant HEPS/FAC/DAST Inspections (\$913,333). This project will include the performance of regulatory required high energy piping surveillance (“HEPS”), deaerator and its storage tank (“DAST”) mid cycle inspection, and flow accelerated corrosion (“FAC”) inspection; and
- Four additional projects for Covert totaling \$527,500 in expenses, with each individual project representing \$275,000 or less in expenses. These projects include NERC relay and DC testing, ITC switchyard upgrades, gas turbine exhaust expansion joints repairs, and 345 kV transformer bushing power factor testing.

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Karn Units 3 and 4 Major Maintenance

Q. Please describe Karn Units 3 and 4 Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 4, column (d), Karn Units 3 and 4 Major Maintenance expense is forecasted to be \$2.502 million in the projected test year ending February 28, 2026, and includes:

- Karn Units 3 and 4 Periodic Outage Major Maintenance (\$355,833). The scope of this project is to perform boiler maintenance activities during scheduled periodic outages during the projected test year. Expenses include planning, engineering services, materials, and overtime labor;
- Karn Units 3 and 4 HEPS/FAC/DAST Inspections (\$375,000 per unit). This project will include the performance of regulatory required inspections;
- Karn Unit 3 Turbine Valve Inspections (\$241,667). The scope of this project is to perform the Karn Unit 3 turbine valve inspections;
- Karn Unit 4 Main Transformer Bladder Replacement (\$208,333). The scope of this project is to replace the bladder. The main transformer conservator bladder is broken and open to atmosphere, making the oil susceptible to air bubbles and increasing the risk of transformer failure; and
- Fourteen additional projects for Karn Units 3 and 4 totaling \$946,333 in expenses, with each individual project representing \$150,000 or less in expenses. These projects include critical motor major maintenance, forced draft and induced draft fan alignments, station power relay maintenance, and opacity critical equipment repairs.

Zeeland Plant Major Maintenance

Q. Please describe Zeeland Plant Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 6, column (d), Zeeland Plant Major Maintenance expense is forecasted to be \$5.232 million in the projected test year ending February 28, 2026, and includes:

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- Zeeland Plant LTSA — Running Maintenance Contract (\$2,048,614). Consumers Energy has a long-term maintenance agreement with GE to perform the major maintenance and capital repairs necessary to maintain unit reliability. This item represents the O&M component of that service agreement;
- Zeeland Plant Capacity Factor Used for Water and Chemicals (\$1,255,417). This item provides for the city water used by the Zeeland Plant, and for the chemicals required to operate the water purification systems that are used to purify the makeup water prior to use;
- Base Outage — Boiler Plant Equipment (\$558,333). During planned and scheduled periodic outages, inspections and repairs are performed. Base boiler maintenance and outage is needed to complete condition assessment inspections of the boiler and major components, complete repairs on valves and large plant equipment, and complete repairs that are identified during shutdowns and condition assessments;
- Zeeland Site Commons Deep Well Injection Cleaning (\$323,333). The scope of this project is the third-party cleaning of the well. Cleaning the well allows Zeeland to continue to operate in the most economical means practical and maintain the required plant equipment. Failure to clean the well would require the plant to blowdown all cooling tower concentrate to the city sewer at a considerable expense. This activity is performed on a triennial basis; and
- Fourteen additional projects totaling \$1,045,984 in expenses, with each individual project representing \$208,333 or less in expenses. These include excitation and isolation transformer testing and maintenance, HEPS, FAC inspection, large oil-filled transformer maintenance, breaker maintenance, and NERC-required relay testing.

Jackson Plant Major Maintenance

Q. Please describe Jackson Plant Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 7, column (d), Jackson Plant Major Maintenance expense is forecasted to be \$3.852 million in the projected test year ending February 28, 2026. This forecasted expense consists of:

- Jackson Plant Capacity Factor Used for Water and Chemicals (\$1,900,000). This item provides for the city water used by the Jackson Plant, and for the chemicals required to operate the water purification systems that are used to purify the makeup water prior to use. The projected expense is based upon

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historical monthly invoice values as well as consideration of the capital project previously discussed in this testimony for site generating water;

- Jackson Plant Non-LTSA Turbine and jet engine repairs (\$391,667). The scope of this major maintenance is to perform jet engine repairs including bushing replacements every 12,000 hours;
- Jackson Plant LTSA — Running Maintenance Contract (\$508,333). Consumers Energy has a long-term maintenance agreement with GE to perform the major maintenance and capital repairs necessary to maintain unit reliability. This item represents the O&M component of that service agreement;
- Jackson Plant Base Outage - Boiler plant equipment (\$250,000). During planned and scheduled periodic outages, inspections and repairs are performed. Base boiler maintenance and outage is needed to complete condition assessment inspections of the boiler and major components, complete repairs on valves and large plant equipment, and complete repairs that are identified during shutdowns and condition assessments; and
- Ten additional projects totaling \$801,565 with each individual project representing \$241,853 or less in expenses. These include HEPS, FAC, pre-Filter replacement, high voltage maintenance and NERC testing, and filter house roof maintenance.

LPS Major Maintenance

Q. Please describe LPS Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 9, column (d), LPS Major Maintenance expense is forecasted to be \$4.445 million in the projected test year ending February 28, 2026, including:

- Fish Barrier Net - Installation, cleaning, and repairs and removal (\$2,140,000). This is a FERC regulatory requirement. The net is installed annually and maintained to meet FERC license requirements (and the requirements of a Settlement Agreement with federal and state natural resource agencies) and minimizes the impact of LPS on fish in Lake Michigan;
- Nine Year Unit Mechanical Interval Inspection and Replacement (\$570,000). The scope of this project is to perform replacement of common wear elements and consumable items associated with the pump/turbine units. This work will

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include the first nine-year maintenance interval for each of the six units as well as up front planning and procurement funding in the first year;

- Reservoir remediation (\$535,833). This is FERC required and related to dam safety to ensure the Company maintains the integrity of the Ludington pond; and
- Twenty-two additional projects totaling \$1,199,508, with each individual project representing less than \$161,000 in expenses. These include asphalt liner inspection repairs, penstock condition assessment and monitoring study, Depression Air Compressor Maintenance, periodic outage inspections and non-destructive examination, lube oil room repair, Polychlorinated Biphenyl removal and disposal, and powerhouse slope terrace drain cleanout.

Hydro Major Maintenance

Q. Please describe Hydro Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 10, column (d), Hydro Major Maintenance expense is forecasted to be \$5.776 million in the projected test year ending February 28, 2026, and includes:

- Hydro License Initiatives (\$2,158,667). A FERC requirement, this item resulted from the relicensing of Au Sable, Manistee, and Muskegon River dams, with the main result being that the Company has annual license commitments. License commitments include some recreation, fish payments, and water quality such as upwelling systems licenses;
- Hydro annual FERC Dam Safety Requirements including Part 12 Inspections (\$1,446,475). The scope of this project is to perform the FERC-required dam safety inspections on an annual basis, and the FERC-required Part 12 inspections on each dam every five years (FERC Part 12 regulations are discussed in Mr. Monroe's direct testimony). A similar level of expense is budgeted annually from 2025 through 2028;
- Hardy Intake Tower Brick Repair (\$241,667). The scope of this project is to replace all the deteriorated interior brick inside the intake tower for the full height. The Hardy intake tower brickwork has been slowly deteriorating for the last few years. The bricks are crumbling to the touch and has areas with significant delamination throughout the entire height of the walls (34ft). If the deterioration becomes significant enough, it may impact the headgate hoists and the head gates installation safety of the Operations staff;

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- Tippy Spillway Chamber Inspections and Repairs (\$202,500). The project scope includes performing spillway chamber inspections, engineering for spillway chamber repairs and construction of repairs. The Tippy spillway chambers are hollow chambers underneath the spillway. In the spillway chambers, the concrete is deteriorated, rebar is exposed, and there is seepage present;
- Hydro Concrete Repairs (\$206,958). The scope of this project is to make necessary repairs to deteriorating concrete at all 13 River Hydro facilities. This budgeted amount will allow for the performance of necessary repairs which are identified after spring flows or general deterioration. The identification of large concrete repairs will be considered in the annual budgeting process; and
- Twenty-six additional projects totaling \$1,520,083 with each individual project representing \$150,000 or less in expenses. These projects include Cooke Powerhouse Divider Pier, Foote Auxiliary Spillway Pilot Channel and Embankment Crest Grading Project, Tippy Log Chute Repairs, base outage funding, headgate evaluation and repairs, relief well piezometer cleaning, and condition/risk assessments.

Solar Major Maintenance

Q. Please describe Solar Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 11, column (d), Solar Major Maintenance expense is forecasted to be \$0.677 million in the projected test year ending February 28, 2026 and includes three projects, all to provide IT support for the Mustang Mile, Muskegon Solar, and Washtenaw Solar IRP solicitation projects. For each of the solar sites, the major maintenance funding includes plant setup in SAP, and payment of the OSISoft PI Historian and Bazefield SCADA overlay license fees.

Admin and Other Major Maintenance

Q. Please describe Admin and Other Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 12, column (d), Admin and Other Major Maintenance expense is forecasted to be \$0.150 million in the projected test year ending

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February 28, 2026 and includes one project: Generation control systems cyber maintenance software support. Specifically, this project provides funding for software maintenance contracts from multiple vendor systems that are not part of the DCS control vendor service contracts.

Classic 7 Major Maintenance

Q. Please describe Classic 7 (B.C. Cobb (“Cobb”), J.C. Weadock (“Weadock”), and J.R. Whiting (“Whiting”) units) Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 5, column (d), Classic 7 Major Maintenance expense is forecasted to be \$0.218 million in the projected test year ending February 28, 2026.

Q. Why is Consumers Energy projecting to spend \$0.218 million in Major Maintenance on the Classic 7 units in the projected test year ending February 28, 2026?

A. Although the Classic 7 units were retired in 2016, environmental regulations require the continued maintenance of the on-site ash ponds, which includes Cobb landfill and ash pond O&M, Weadock landfill license and inspections, and Whiting ash pond post-closure care.

**KARN AND CAMPBELL RETENTION AND SEPARATION PLAN
EXPENSE**

Q. What are the projected costs for the Company’s Karn and Campbell Retention and Separation plans?

A. As reflected on Exhibit A-43 (RTB-4), page 1, line 5, the Company incurred actual expense of \$17.348 million in 2023, and is projecting expense of \$11.158 million in the 14-month projected bridge period, and \$4.621 million in the projected test year. The actual 2023 expense of \$17.348 million is based upon expense of \$1.501 million for Karn and

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1 \$15.847 million for Campbell. The 14-month projected bridge period expense of
2 \$11.158 million is entirely based upon expense of \$11.158 million for Campbell. The
3 projected test year expense of \$4.621 million is based upon expense of \$4.621 million for
4 Campbell.

5 **Q. Is the Company requesting O&M recovery of the \$4.621 million projected amount**
6 **for the projected test year?**

7 A. No. The Company is not requesting approval of this projected amount in Generation O&M
8 expense. The Company received approval in electric rate case, Case No. U-20697, to defer
9 the recovery of the Karn Retention and Separation O&M amounts for 2021 through 2023.
10 The Company received approval to defer the recovery of the Campbell retention and
11 separation amounts in the Settlement Agreement in its 2021 IRP. As such, the projected
12 amounts for 2023 through the projected test year ending February 28, 2026 are not included
13 in the Total O&M amounts on Exhibit A-43 (RTB-4), page 1, line 6, columns (b), (c) and
14 (d). Company witness Aponte supports regulatory asset treatment of these expenses in her
15 direct testimony.

16 **Q. Please describe the Karn retention and separation plan.**

17 A. The Karn retention and separation plan is a people strategy that the Company has
18 implemented to ensure that it could retain the necessary qualified employees to operate
19 Karn Units 1 and 2 through their retirement date in May 2023, as well as during the cold
20 and dark time period following retirement. The cold and dark condition refers to the period
21 following plant retirement and prior to plant decommissioning. During this period, limited
22 environmental remediation and perhaps partial demolition is performed. The facility may
23 be physically secured with fencing and other measures to prevent vandalism or theft so as

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1 to limit liability risks. On June 7, 2019, the MPSC approved the Company's 2018 IRP
2 Settlement Agreement, which included the retirement of Karn Units 1 and 2 in May 2023.
3 The Company's IRP included detailed support of the Company's need to implement a
4 retention and separation plan to ensure that it could operate the plants safely and reliably
5 through their retirement date.

6 **Q. What is the purpose of the retention component of the Company's plan?**

7 A. The Company had a strong interest in keeping qualified employees working at Karn Units 1
8 and 2 through their retirement date to ensure safe and reliable operations. The retention
9 component will allow the Company to retain employees that may seek employment at other
10 Company locations or outside of the Company. The Company's ability to hire new
11 employees at Karn Units 1 and 2 became increasingly difficult given the short remaining
12 lifespan of the units and, to the extent that the Company had the ability to hire new
13 employees, the training time necessary for any new hires provided a significant challenge
14 to operating the units both safely and reliably. The retention component utilized the best
15 practices that the Company employed in retiring the Classic 7.

16 **Q. What is the purpose of the separation component of the Company's plan?**

17 A. Now that Karn Units 1 and 2 are retired, the Company is following the terms of the
18 collective bargaining agreement for OM&C employees represented by the Utility Workers
19 Union of America ("UWUA"), and the terms of the employee handbook policy and
20 separation plan for non-represented exempt and non-exempt employees. The structure and
21 amount of the severance offers varies based on employee salary and classification due to
22 differences in the terms of the separation plan covering non-represented employees and the
23 bargaining agreement for UWUA-represented employees. In the event that exempt or

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1 non-exempt employees cannot find placement within the Company within 60 miles from
2 their current location, they will be offered involuntary severance in accordance with the
3 terms of the Company's Salaried Separation Plan. The Company's Working Agreement
4 with the UWUA governs separation for OM&C employees who elect to leave the Company
5 rather than accept a new position as well as relocation expenses if they accept a position
6 more than 60 miles away from their current location.

7 **Q. What are the benefit types associated with the Karn retention and separation plan?**

8 A. The Karn retention and separation plan includes three benefit types: retention benefits,
9 severance benefits, and relocation and moving costs.

10 **Q. Please describe the retention benefits associated with the Karn retention and**
11 **separation plan.**

12 A. The retention benefits associated with the Karn retention and separation plan include three
13 payment components: a signing incentive, annual incentives, and a final retention
14 incentive.

15 Employees received a signing incentive equal to 15% of their base pay if they
16 signed a retention agreement in October 2019. By signing the retention agreement, the
17 employee agreed to forfeit their transfer rights under the current working agreement (for
18 union employees) or under Company policy (for exempt and non-exempt employees). The
19 employee had to stay at Karn until October 31, 2020 to receive the payment; if the
20 employee stayed until that date, the incentive was paid out to the employee within 30 days.
21 If the employee separated from the Company before October 31, 2020, the employee
22 forfeited the signing incentive.

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1 Employees receive an annual incentive which graduated from 20% to 30% of their
2 base pay for service each November in years 2019, 2020, and 2021, for staying at Karn and
3 rendering service for the next 12 months. The employee had to stay at Karn until
4 October 31 of the following year to receive the payment; if the employee stayed until that
5 date, the incentive was paid out to the employee within 30 days. If the employee separated
6 from the Company before October 31 of the next year, the employee forfeited the annual
7 incentive. Eligible employees received their first annual incentive payment in November
8 2020, a second payment in November 2021, and a third payment in November 2022.

9 Employees received their final retention incentive equal to 60% of their base pay
10 following plant retirement if the employee was still at Karn. The payment was intended to
11 incentivize employees to stay until the plant goes cold and dark and compensate employees
12 for the service they rendered for the eight months (November 2022 through June 2023)
13 prior to the payment.

14 **Q. Please describe the severance benefits associated with the Karn retention and**
15 **separation plan.**

16 A. The severance benefits associated with the Karn retention and separation plan includes
17 initial recognition of a severance benefit to be paid, recognition of additional severance
18 earned (one week of pay per year of service), and recognition of the accretion of a final
19 severance benefit.

20 **Q. Why does the Company anticipate the need to make severance payments associated**
21 **with the retirement of Karn Units 1 and 2?**

22 A. The Company is proud of the fact that following the retirement of the Classic 7 in 2016,
23 all Company employees that desired to continue employment with the Company were able

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1 to do so. However, the Company is also aware of the fact that it has fewer Company
2 locations (11 within 60 miles of the Karn site) to which employees can relocate, than it did
3 in 2016. As such, the Company anticipated the need to make severance payments to those
4 employees that cannot find placement. As I previously stated, the Company is following
5 the terms of the collective bargaining agreement for OM&C employees represented by the
6 UWUA, and the terms of the employee handbook policy and separation plan for
7 non-represented exempt and non-exempt employees.

8 **Q. Please explain the relevant details of the collective bargaining agreement for OM&C**
9 **employees.**

10 A. The collective bargaining agreement for OM&C employees, in Article VII, Section 17, and
11 the Generation Operations Coal Closing Agreement provide that employees will be placed
12 in either a corresponding position, or if none exists, in a vacant position he/she is qualified
13 to perform within 60 miles of his/her current headquarters. Per Article XVII of the
14 collective bargaining agreement, employees who are released due to lack of work, and are
15 not placed as described above, are provided a separation allowance consisting of straight
16 time pay for five regular workdays for each year of continuous service with the
17 Company. Due to the lack of Company locations within 60 miles of Karn Units 1 and 2,
18 as described above, it was anticipated that some employees would be eligible for a
19 separation allowance.

20 **Q. Please describe the Campbell retention plan.**

21 A. The Campbell retention plan is a people strategy that the Company has proposed in its 2021
22 IRP. As previously discussed, the Company's 2021 IRP PCA reflects the retirement of
23 Campbell Units 1, 2, and 3 on May 31, 2025. This retention plan was proposed in order to

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1 retain employees through the closure of the three Campbell units. This strategy is
2 necessary to ensure that the Company can operate the Campbell units safely and reliably
3 through their retirement date. This incentive program is the same program that is currently
4 in place for employees at the Karn site.

5 **Q. What is the purpose of the retention component of the Company's plan?**

6 A. For similar reasons described in the Karn retention plan, the Company has a strong interest
7 in keeping qualified employees working at the Campbell site through their retirement date
8 to ensure safe and reliable operations. The retention component will allow the Company
9 to retain employees that may seek employment at other Company locations or outside of
10 the Company. Similar to the situation at the Karn site, it will be increasingly difficult to
11 hire new employees at the Campbell site given the short remaining lifespan of the units
12 and, to the extent that the Company has the ability to hire new employees, the training time
13 necessary for any new hires will provide a significant challenge to operating the three units
14 both safely and reliably.

15 **Q. What is the purpose of the separation component of the Company's plan?**

16 A. When the Campbell units are retired, the Company plans to follow the terms of the
17 collective bargaining agreement for OM&C employees represented by the UWUA, and the
18 terms of the employee handbook policy and separation plan for non-represented exempt
19 and non-exempt employees. The structure and amount of the severance offers will vary
20 based on employee salary and classification due to differences in the terms of the separation
21 plan covering non-represented employees and the bargaining agreement for
22 UWUA-represented employees. In the event that exempt or non-exempt employees cannot
23 find placement within the Company within 60 miles from their current location, they will

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1 be offered involuntary severance in accordance with the terms of the Company's Salaried
2 Separation Plan. The Company's Working Agreement with the UWUA governs separation
3 for OM&C employees who elect to leave the Company rather than accept a new position
4 as well as relocation expenses if they accept a position more than 60 miles away from their
5 current location.

6 **Q. What are the benefit types associated with the Campbell retention plan?**

7 A. Similar to the Karn retention and separation plan, the Campbell retention plan includes
8 three benefit types: retention benefits, severance benefits, and relocation and moving costs.

9 **Q. Please describe the retention benefits associated with the Campbell retention plan.**

10 A. The retention benefits associated with the Campbell retention plan include three payment
11 components: a signing incentive, periodic incentives, and a final retention incentive. The
12 timeline for retention benefits reflects approval of the Settlement Agreement in the
13 Company's 2021 IRP in June 2022.

14 Employees received a signing incentive equal to 15% of their base pay if they
15 signed a retention agreement in July 2022. By signing the retention agreement, the
16 employee agreed to forfeit their transfer rights under the current working agreement (for
17 union employees) or under Company policy (for exempt and non-exempt employees). The
18 employee had to stay at Campbell until October 31, 2022 to receive the payment; if the
19 employee stayed until that date, the incentive was paid out to the employee within 30 days.
20 If the employee separated from the Company before October 31, 2022, the employee
21 forfeited the signing incentive.

22 Employees receive a periodic incentive which graduates from 20% to 30% of their
23 base pay for service each November in years 2022, 2023, and 2024, for staying at Campbell

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1 and rendering service for a certain period. Specifically, for service provided July 2022
2 through October 2022, employees received 20% of their base pay. For service provided
3 November 2022 through October 2023, employees received 25% of base pay. For service
4 provided November 2023 through October 2024, employees will receive 30% of base pay.
5 The employee must stay at Campbell until October 31 of the given year to receive the
6 payment; if the employee stays until that date, the incentive was/will be paid out to the
7 employee within 30 days. If the employee separates from the Company before October 31
8 of the given year, the employee forfeits the annual incentive.

9 Employees receive a final retention incentive equal to 60% of their base pay on or
10 about October 31, 2025, if the employee is still at Campbell. The payment is intended to
11 incentivize employees to stay until the plant goes cold and dark and compensate employees
12 for the service they rendered for the 12 months prior to the payment.

13 **Q. Please describe the severance benefits associated with the Campbell retention plan.**

14 A. The severance benefits associated with the Campbell retention plan include initial
15 recognition of a severance benefit to be paid, recognition of additional severance earned
16 (one week of pay per year of service), and recognition of the accretion of a final severance
17 benefit.

18 **Q. Why does the Company anticipate the need to make severance payments associated**
19 **with the retirement of Campbell Units 1, 2, and 3?**

20 A. The Company is proud of the fact that following the retirement of the Classic 7 in 2016,
21 all Company employees that desired to continue employment with the Company were able
22 to do so. However, the Company is also aware of the fact that it has fewer Company
23 locations (seven within 60 miles of the Campbell site) to which employees can relocate,

RICHARD T. BLUMENSTOCK
U-21585 DIRECT TESTIMONY

1 than it did in 2016. In addition, the Company will also have retired at least two of the Karn
2 generating units in 2023, thereby further reducing the available positions. As such, the
3 Company has anticipated the need to make severance payments to those employees that
4 cannot find placement. As I previously stated, the Company plans to follow the terms of
5 the collective bargaining agreement for OM&C employees represented by the UWUA, and
6 the terms of the employee handbook policy and separation plan for non-represented exempt
7 and non-exempt employees, as previously discussed for the Karn retention and separation
8 plan.

9 **Q. Does this conclude your direct testimony?**

10 **A.** Yes, it does.

Schedule: B-5.2

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Summary of Actual and Projected Electric Capital Expenditures
For the years 2023 through 2026
(\$000's)

Case No.: U-21585
Exhibit No.: A-12 (RTB-3)
Schedule: B-5.2
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Date: May 2024

**Generation Capital Expenditures
(\$000)**

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)
		Historical Year 12 Months Ended 12/31/2023	Projected Bridge Period			Projected Test Year 12 Mos Ending 2/28/2026
		12 Mos Ended 12/31/2024	2 Mos Ending 2/28/2025	14 Mos Ending 2/28/2025		12 Mos Ending 2/28/2026
1	Steam Power Generation					
2	Environmental	\$ (1,274)	\$ -	\$ -	\$ -	\$ -
3	Routine and Small CapEx	\$ 11,813	\$ 16,565	\$ 554	\$ 17,119	\$ 7,287
4	Total Steam Production	\$ 10,539	\$ 16,565	\$ 554	\$ 17,119	\$ 7,287
5	Hydraulic Power Generation					
6	Routine and Small CapEx	\$ 25,530	\$ 38,052	\$ 4,324	\$ 42,376	\$ 92,258
7	Total hydraulic production	\$ 25,530	\$ 38,052	\$ 4,324	\$ 42,376	\$ 92,258
8	Pumped Storage Generation					
9	Ludington Overhaul	\$ 1,252	\$ -	\$ -	\$ -	\$ -
10	Routine and Small CapEx	\$ 9,389	\$ 8,717	\$ 1,563	\$ 10,279	\$ 15,587
11	Total Pumped Storage Generation	\$ 10,642	\$ 8,717	\$ 1,563	\$ 10,279	\$ 15,587
12	Other Production Plant					
13	Routine and Small CapEx	\$ 812,384	\$ 275,971	\$ 117,803	\$ 393,774	\$ 485,354
14	Total Other Production Plant	\$ 812,384	\$ 275,971	\$ 117,803	\$ 393,774	\$ 485,354
15	SubTotal	\$ 859,095	\$ 339,304	\$ 124,244	\$ 463,548	\$ 600,484
16	Less Contingency	\$ -	\$ -	\$ -	\$ -	\$ -
17	Grand Total	\$ 859,095	\$ 339,304	\$ 124,244	\$ 463,548	\$ 600,484

	(a)	(b)	(c)	(d)	(e)
		Projected			
		2 Mos Ending 2/29/2024	12 Mos Ending 2/28/2025	12 Mos Ending 2/28/2026	26 Mos Ending 2/28/2026
1	Steam Power Generation				
2	Environmental	\$ -	\$ -	\$ -	\$ -
3	Routine and Small CapEx	\$ 3,773	\$ 13,346	\$ 7,287	\$ 24,405
4	Total Steam Production	\$ 3,773	\$ 13,346	\$ 7,287	\$ 24,405
5	Hydraulic Power Generation				
6	Routine and Small CapEx	\$ 2,404	\$ 39,972	\$ 92,258	\$ 134,633
7	Total hydraulic production	\$ 2,404	\$ 39,972	\$ 92,258	\$ 134,633
8	Pumped Storage Generation				
9	Ludington Overhaul				\$ -
10	Routine and Small CapEx	\$ 780	\$ 9,499	\$ 15,587	\$ 25,866
11	Total Pumped Storage Generation	\$ 780	\$ 9,499	\$ 15,587	\$ 25,866
12	Other Production Plant				
13	Routine and Small CapEx	\$ 27,570	\$ 366,204	\$ 485,354	\$ 879,128
14	Total Other Production Plant	\$ 27,570	\$ 366,204	\$ 485,354	\$ 879,128
15	SubTotal	\$ 34,526	\$ 429,022	\$ 600,484	\$ 1,064,032
16	Less Contingency	\$ -	\$ -	\$ -	\$ -
17	Grand Total	\$ 34,526	\$ 429,022	\$ 600,484	\$ 1,064,032

Schedule: B-5.2

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2023 through 2026
(\$000's)

Case No.: U-21585
Exhibit No.: A-12 (RTB-3)
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Generation Capital Expenditures											
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Line No.	Description	Historical Year		Projected Bridge Period						Projected Test Year	
		12 Months Ended 12/31/2023		12 Months Ending 12/31/2024		2 Months Ending 2/28/2025		14 Months Ending 2/28/2025		12 Months Ending 2/28/2026	
1	JHCampbell 1&2	\$	(1,497)	\$	-	\$	-	\$	-	\$	-
2	Contractor		\$ (1,373)		\$ -		\$ -		\$ -		\$ -
3	Labor		\$ (165)		\$ -		\$ -		\$ -		\$ -
4	Materials		\$ 531		\$ -		\$ -		\$ -		\$ -
5	Business Expenses		\$ (29)		\$ -		\$ -		\$ -		\$ -
6	Contingency		\$ -		\$ -		\$ -		\$ -		\$ -
7	Other (Loadings, Chargebacks)		\$ (461)		\$ -		\$ -		\$ -		\$ -
8	JHCampbell 3	\$	456	\$	-	\$	-	\$	-	\$	-
9	Contractor		\$ (618)		\$ -		\$ -		\$ -		\$ -
10	Labor		\$ (207)		\$ -		\$ -		\$ -		\$ -
11	Materials		\$ 1,341		\$ -		\$ -		\$ -		\$ -
12	Business Expenses		\$ (357)		\$ -		\$ -		\$ -		\$ -
13	Contingency		\$ -		\$ -		\$ -		\$ -		\$ -
14	Other (Loadings, Chargebacks)		\$ 296		\$ -		\$ -		\$ -		\$ -
15	DEKarn 1&2	\$	(81)	\$	-	\$	-	\$	-	\$	-
16	Contractor		\$ (62)		\$ -		\$ -		\$ -		\$ -
17	Labor		\$ (13)		\$ -		\$ -		\$ -		\$ -
18	Materials		\$ 14		\$ -		\$ -		\$ -		\$ -
19	Business Expenses		\$ -		\$ -		\$ -		\$ -		\$ -
20	Contingency		\$ -		\$ -		\$ -		\$ -		\$ -
21	Other (Loadings, Chargebacks)		\$ (20)		\$ -		\$ -		\$ -		\$ -
22	DEKarn 3&4	\$	12,935	\$	16,565	\$	554	\$	17,119	\$	7,287
23	Contractor		\$ 6,825		\$ 14,062		\$ 470		\$ 14,532		\$ 6,186
24	Labor		\$ 234		\$ 50		\$ 2		\$ 51		\$ 22
25	Materials		\$ 2,555		\$ -		\$ -		\$ -		\$ -
26	Business Expenses		\$ (1)		\$ -		\$ -		\$ -		\$ -
27	Contingency		\$ -		\$ -		\$ -		\$ -		\$ -
28	Other (Loadings, Chargebacks)		\$ 3,322		\$ 2,453		\$ 82		\$ 2,535		\$ 1,079
29	Zeeland	\$	41,443	\$	36,364	\$	12,153	\$	48,518	\$	50,929
30	Contractor		\$ 27,583		\$ 29,451		\$ 9,843		\$ 39,294		\$ 41,248
31	Labor		\$ 505		\$ 95		\$ 32		\$ 126		\$ 132
32	Materials		\$ 5,583		\$ 389		\$ 130		\$ 519		\$ 545
33	Business Expenses		\$ 37		\$ -		\$ -		\$ -		\$ -
34	Contingency		\$ -		\$ -		\$ -		\$ -		\$ -
35	Other (Loadings, Chargebacks)		\$ 7,735		\$ 6,429		\$ 2,149		\$ 8,578		\$ 9,004
36	Jackson Generating Station	\$	20,979	\$	16,727	\$	2,403	\$	19,130	\$	14,965
37	Contractor		\$ 15,651		\$ 13,719		\$ 1,971		\$ 15,690		\$ 12,274
38	Labor		\$ 430		\$ 30		\$ 4		\$ 34		\$ 27
39	Materials		\$ 1,994		\$ 256		\$ 37		\$ 293		\$ 229
40	Business Expenses		\$ 24		\$ -		\$ -		\$ -		\$ -
41	Contingency		\$ -		\$ -		\$ -		\$ -		\$ -
42	Other (Loadings, Chargebacks)		\$ 2,880		\$ 2,721		\$ 391		\$ 3,112		\$ 2,435
43	Covert	\$	680,305	\$	28,441	\$	5,646	\$	34,087	\$	61,483
44	Contractor		\$ 11,579		\$ 23,709		\$ 4,707		\$ 28,415		\$ 51,252
45	Labor		\$ 165		\$ -		\$ -		\$ -		\$ -
46	Materials		\$ 972		\$ 131		\$ 26		\$ 157		\$ 283
47	Business Expenses		\$ 664,876		\$ -		\$ -		\$ -		\$ -
48	Contingency		\$ -		\$ -		\$ -		\$ -		\$ -
49	Other (Loadings, Chargebacks)		\$ 2,713		\$ 4,602		\$ 914		\$ 5,515		\$ 9,948
50	Solar	\$	69,040	\$	152,455	\$	97,117	\$	249,572	\$	275,959
51	Contractor		\$ 64,558		\$ 147,043		\$ 93,669		\$ 240,712		\$ 266,162
52	Labor		\$ 193		\$ 534		\$ 340		\$ 874		\$ 966
53	Materials		\$ -		\$ -		\$ -		\$ -		\$ -
54	Business Expenses		\$ 3,269		\$ 915		\$ 583		\$ 1,497		\$ 1,656
55	Contingency		\$ -		\$ -		\$ -		\$ -		\$ -
56	Other (Loadings, Chargebacks)		\$ 1,020		\$ 3,964		\$ 2,525		\$ 6,489		\$ 7,175

MICHIGAN PUBLIC SERVICE COMMISSION

Schedule: B-5.2

Case No.: U-21585

Exhibit No.: A-12 (RTB-3)

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Date: May 2024

Consumers Energy Company

Summary of Actual and Projected Electric Capital Expenditures

For the years 2023 through 2026

(\$000's)

Generation Capital Expenditures

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Historical Year 12 Months Ended 12/31/2023		12 Months Ending 12/31/2024		2 Months Ending 2/28/2025		14 Months Ending 2/28/2025		Projected Test Year 12 Mos Ending 2/28/2026	
57	Classic /	-		-		-					
58	Contractor		-		-		-		-		-
59	Labor		-		-		-		-		-
60	Materials		-		-		-		-		-
61	Business Expenses		-		-		-		-		-
62	Contingency		-		-		-		-		-
63	Other (Loadings, Chargebacks)		-		-		-		-		-
64	Hydros	25,530		38,052		4,324		42,376		92,258	
65	Contractor		16,949		28,653		3,256		31,909		69,470
66	Labor		1,116		282		32		314		683
67	Materials		867		-		-		-		-
68	Business Expenses		564		-		-		-		-
69	Contingency		-		-		-		-		-
70	Other (Loadings, Chargebacks)		6,034		9,117		1,036		10,153		22,105
71	Ludington	10,642		8,717		1,563		10,279		15,587	
72	Contractor		3,840		13,811		2,476		16,286		24,695
73	Labor		195		148		27		175		265
74	Materials		1,543		-		-		-		-
75	Business Expenses		(13)		-		-		-		-
76	Contingency		-		-		-		-		-
77	Other (Loadings, Chargebacks)		5,076		(5,242)		(940)		(6,182)		(9,374)
78	Admin and Other	544		2,311		484		2,795		3,096	
79	Contractor		69		1,386		290		1,676		1,857
80	Labor		23		-		-		-		-
81	Materials		351		-		-		-		-
82	Business Expenses		1		841		176		1,017		1,127
83	Contingency		-		-		-		-		-
84	Other (Loadings, Chargebacks)		100		84		18		101		112
85	Battery Storage	74		39,672		-		39,672		78,921	
86	Contractor		31		37,320		-		37,320		74,510
87	Labor		14		1,225		-		1,225		2,325
88	Materials		-		-		-		-		-
89	Business Expenses		-		-		-		-		-
90	Contingency		-		-		-		-		-
91	Other (Loadings, Chargebacks)		29		1,127		-		1,127		2,086
92	All Other Environmental	(1,274)		-		-		-		-	
93	Contractor		(993)		-		-		-		-
94	Labor		(61)		-		-		-		-
95	Materials		26		-		-		-		-
96	Business Expenses		46		-		-		-		-
97	Contingency		-		-		-		-		-
98	Other (Loadings, Chargebacks)		(292)		-		-		-		-
99	Total Capital	859,095	859,095	339,304	339,304	124,244	124,244	463,548	463,548	600,484	600,484

Schedule: B-5.2

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Summary of Actual and Projected Electric Capital Expenditures
For the years 2023 through 2026
(\$000's)

Case No.: U-21585
Exhibit No.: A-12 (RTB-3)
Schedule: B-5.2
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Witness: RTBlumenstock
Date: May 2024

Generation Capital Expenditures

Line No.	Description	Projected			
		2 Mos Ending 2/28/2024	12 Mos Ending 2/28/2025	12 Mos Ending 2/28/2026	26 Mos Ending 2/28/2026
1	JHCampbell 1&2	\$ -	\$ -	\$ -	\$ -
2	Contractor	\$ -	\$ -	\$ -	\$ -
3	Labor	\$ -	\$ -	\$ -	\$ -
4	Materials	\$ -	\$ -	\$ -	\$ -
5	Business Expenses	\$ -	\$ -	\$ -	\$ -
6	Contingency	\$ -	\$ -	\$ -	\$ -
7	Other (Loadings, Chargebacks)	\$ -	\$ -	\$ -	\$ -
8	JHCampbell 3	\$ -	\$ -	\$ -	\$ -
9	Contractor	\$ -	\$ -	\$ -	\$ -
10	Labor	\$ -	\$ -	\$ -	\$ -
11	Materials	\$ -	\$ -	\$ -	\$ -
12	Business Expenses	\$ -	\$ -	\$ -	\$ -
13	Contingency	\$ -	\$ -	\$ -	\$ -
14	Other (Loadings, Chargebacks)	\$ -	\$ -	\$ -	\$ -
15	DEKarn 1&2	\$ -	\$ -	\$ -	\$ -
16	Contractor	\$ -	\$ -	\$ -	\$ -
17	Labor	\$ -	\$ -	\$ -	\$ -
18	Materials	\$ -	\$ -	\$ -	\$ -
19	Business Expenses	\$ -	\$ -	\$ -	\$ -
20	Contingency	\$ -	\$ -	\$ -	\$ -
21	Other (Loadings, Chargebacks)	\$ -	\$ -	\$ -	\$ -
22	DEKarn 3&4	\$ 3,773	\$ 13,346	\$ 7,287	\$ 24,405
23	Contractor	\$ 3,203	\$ 11,329	\$ 6,186	\$ 20,718
24	Labor	\$ 11	\$ 40	\$ 22	\$ 73
25	Materials	\$ -	\$ -	\$ -	\$ -
26	Business Expenses	\$ -	\$ -	\$ -	\$ -
27	Contingency	\$ -	\$ -	\$ -	\$ -
28	Other (Loadings, Chargebacks)	\$ 559	\$ 1,977	\$ 1,079	\$ 3,614
29	Zeeland	\$ 15,536	\$ 32,982	\$ 50,929	\$ 99,447
30	Contractor	\$ 12,582	\$ 26,712	\$ 41,248	\$ 80,542
31	Labor	\$ 40	\$ 86	\$ 132	\$ 259
32	Materials	\$ 166	\$ 353	\$ 545	\$ 1,064
33	Business Expenses	\$ -	\$ -	\$ -	\$ -
34	Contingency	\$ -	\$ -	\$ -	\$ -
35	Other (Loadings, Chargebacks)	\$ 2,747	\$ 5,831	\$ 9,004	\$ 17,582
36	Jackson Generating Station	\$ 1,890	\$ 17,240	\$ 14,965	\$ 34,095
37	Contractor	\$ 1,550	\$ 14,140	\$ 12,274	\$ 27,965
38	Labor	\$ 3	\$ 31	\$ 27	\$ 61
39	Materials	\$ 29	\$ 264	\$ 229	\$ 522
40	Business Expenses	\$ -	\$ -	\$ -	\$ -
41	Contingency	\$ -	\$ -	\$ -	\$ -
42	Other (Loadings, Chargebacks)	\$ 307	\$ 2,805	\$ 2,435	\$ 5,547
43	Covert	\$ 4,175	\$ 29,912	\$ 61,483	\$ 95,570
44	Contractor	\$ 3,480	\$ 24,935	\$ 51,252	\$ 79,668
45	Labor	\$ -	\$ -	\$ -	\$ -
46	Materials	\$ 19	\$ 138	\$ 283	\$ 440
47	Business Expenses	\$ -	\$ -	\$ -	\$ -
48	Contingency	\$ -	\$ -	\$ -	\$ -
49	Other (Loadings, Chargebacks)	\$ 676	\$ 4,840	\$ 9,948	\$ 15,463
50	Solar	\$ 5,144	\$ 244,428	\$ 275,959	\$ 525,531
51	Contractor	\$ 4,961	\$ 235,751	\$ 266,162	\$ 506,875
52	Labor	\$ 18	\$ 855	\$ 966	\$ 1,839
53	Materials	\$ -	\$ -	\$ -	\$ -
54	Business Expenses	\$ 31	\$ 1,467	\$ 1,656	\$ 3,153
55	Contingency	\$ -	\$ -	\$ -	\$ -
56	Other (Loadings, Chargebacks)	\$ 134	\$ 6,355	\$ 7,175	\$ 13,664

Schedule: B-5.2

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Summary of Actual and Projected Electric Capital Expenditures

For the years 2023 through 2026

(\$000's)

Case No.: U-21585

Exhibit No.: A-12 (RTB-3)

Schedule: B-5.2

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Witness: RTBlumenstock

Date: May 2024

Generation Capital Expenditures

Line No.	Description	Projected			
		2 Mos Ending 2/29/2024	12 Mos Ending 2/28/2025	12 Mos Ending 2/28/2026	26 Mos Ending 2/28/2026
57	Classic 7	\$ -	\$ -	\$ -	\$ -
58	Contractor	\$ -	\$ -	\$ -	\$ -
59	Labor	\$ -	\$ -	\$ -	\$ -
60	Materials	\$ -	\$ -	\$ -	\$ -
61	Business Expenses	\$ -	\$ -	\$ -	\$ -
62	Contingency	\$ -	\$ -	\$ -	\$ -
63	Other (Loadings, Chargebacks)	\$ -	\$ -	\$ -	\$ -
64	Hydros	\$ 2,404	\$ 39,972	\$ 92,258	\$ 134,633
65	Contractor	\$ 1,810	\$ 30,099	\$ 69,470	\$ 101,379
66	Labor	\$ 18	\$ 296	\$ 683	\$ 996
67	Materials	\$ -	\$ -	\$ -	\$ -
68	Business Expenses	\$ -	\$ -	\$ -	\$ -
69	Contingency	\$ -	\$ -	\$ -	\$ -
70	Other (Loadings, Chargebacks)	\$ 576	\$ 9,577	\$ 22,105	\$ 32,258
71	Ludington	\$ 780	\$ 9,499	\$ 15,587	\$ 25,866
72	Contractor	\$ 1,235	\$ 15,051	\$ 24,695	\$ 40,982
73	Labor	\$ 13	\$ 161	\$ 265	\$ 440
74	Materials	\$ -	\$ -	\$ -	\$ -
75	Business Expenses	\$ -	\$ -	\$ -	\$ -
76	Contingency	\$ -	\$ -	\$ -	\$ -
77	Other (Loadings, Chargebacks)	\$ (469)	\$ (5,713)	\$ (9,374)	\$ (15,556)
78	Admin and Other	\$ 170	\$ 2,625	\$ 3,096	\$ 5,891
79	Contractor	\$ 102	\$ 1,574	\$ 1,857	\$ 3,533
80	Labor	\$ -	\$ -	\$ -	\$ -
81	Materials	\$ -	\$ -	\$ -	\$ -
82	Business Expenses	\$ 62	\$ 955	\$ 1,127	\$ 2,144
83	Contingency	\$ -	\$ -	\$ -	\$ -
84	Other (Loadings, Chargebacks)	\$ 6	\$ 95	\$ 112	\$ 214
85	Battery Storage	\$ 655	\$ 39,017	\$ 78,921	\$ 118,594
86	Contractor	\$ 655	\$ 36,665	\$ 74,510	\$ 111,831
87	Labor	\$ -	\$ 1,225	\$ 2,325	\$ 3,550
88	Materials	\$ -	\$ -	\$ -	\$ -
89	Business Expenses	\$ -	\$ -	\$ -	\$ -
90	Contingency	\$ -	\$ -	\$ -	\$ -
91	Other (Loadings, Chargebacks)	\$ -	\$ 1,127	\$ 2,086	\$ 3,213
92	All Other Environmental	\$ -	\$ -	\$ -	\$ -
93	Contractor	\$ -	\$ -	\$ -	\$ -
94	Labor	\$ -	\$ -	\$ -	\$ -
95	Materials	\$ -	\$ -	\$ -	\$ -
96	Business Expenses	\$ -	\$ -	\$ -	\$ -
97	Contingency	\$ -	\$ -	\$ -	\$ -
98	Other (Loadings, Chargebacks)	\$ -	\$ -	\$ -	\$ -
99	SubTotal	\$ 34,526	\$ 429,022	\$ 600,484	\$ 1,064,032
100	Less Contingency	\$ -	\$ -	\$ -	\$ -
101	Grand Total	\$ 34,526	\$ 429,022	\$ 600,484	\$ 1,064,032

Schedule: B-5.2

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Summary of Actual and Projected Electric Capital Expenditures
For the years 2023 through 2026

(\$000's)

Case No.: U-21585

Exhibit No.: A-12 (RTB-3)

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Date: May 2024

Generation Capital Expenditures

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Period			Projected Test Year
		12 Months Ended 12/31/2023	12 Months Ending 12/31/2024	2 Months Ending 2/28/2025	14 Months Ending 2/28/2025	12 Months Ending 2/28/2026
1	Contractor	\$ 144,039	\$ 309,154	\$ 116,682	\$ 425,836	\$ 547,655
2	Labor	\$ 2,430	\$ 2,363	\$ 436	\$ 2,799	\$ 4,420
3	Materials	\$ 15,776	\$ 776	\$ 193	\$ 969	\$ 1,057
4	Business Expenses	\$ 668,417	\$ 1,756	\$ 759	\$ 2,515	\$ 2,783
5	Contingency	\$ -	\$ -	\$ -	\$ -	\$ -
6	Other (Loadings, Chargebacks)	\$ 28,433	\$ 25,255	\$ 6,174	\$ 31,430	\$ 44,571
	Total	\$ 859,095	\$ 339,304	\$ 124,244	\$ 463,548	\$ 600,484

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)
		Projected				
		12 Months Ending 12/31/2024	2 Months Ending 2/28/2025	14 Months Ending 2/28/2025	12 Months Ending 2/28/2026	26 Months Ending 2/28/2026
1	Contractor	\$ 309,154	\$ 116,682	\$ 425,836	\$ 547,655	\$ 973,491
2	Labor	\$ 2,363	\$ 436	\$ 2,799	\$ 4,420	\$ 7,219
3	Materials	\$ 776	\$ 193	\$ 969	\$ 1,057	\$ 2,025
4	Business Expenses	\$ 1,756	\$ 759	\$ 2,515	\$ 2,783	\$ 5,298
5	Contingency	\$ -	\$ -	\$ -	\$ -	\$ -
6	Other (Loadings, Chargebacks)	\$ 25,255	\$ 6,174	\$ 31,430	\$ 44,571	\$ 76,000
	Total	\$ 339,304	\$ 124,244	\$ 463,548	\$ 600,484	\$ 1,064,032

MICHIGAN PUBLIC SERVICE COMMISSION

Schedule: B-5.2

Case No.: U-21585
Exhibit No.: A-12 (RTB-3)
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Witness: RTBlumenstock
Date: May 2024

Consumers Energy Company

Summary of Actual and Projected Electric Capital Expenditures
For the years 2023 through 2026
(\$000's)

Generation Capital Expenditures

Line No.	(a) Calendar Year	(b) Tier 1 Portfolio	(c) Tier 2 Portfolio	(d) Project Type	(e) Project Classification	(f) Work Item Description	(g) Projected Amount	(h) Actual Amount
1	2023	Coal Generation	Campbell 3	Routine	Environmental	SCR Catalyst Management	\$ 2,303	\$ 2,254
2	2023	Gas Generation	Covert Commons	Routine	Condition-based	Long Term Service Agreement - Running capital contract	\$ 9,761	\$ 9,182
3	2023	Gas Generation	Covert Commons	Non-Routine	Acquisition	Covert Generating Facility Acquisition	\$ 815,000	\$ 663,142
4	2023	Gas Generation	Covert Commons	Non-Routine	Regulatory	Covert Information Technology Room		\$ 2,060
5	2023	Gas Generation	Covert Commons	Non-Routine	Regulatory	Covert Security and Network		\$ 2,208
6	2023	Gas Generation	Covert Commons	Non-Routine	Condition-based	Covert Spare generator stepup transformer		\$ 1,723
7	2023	Gas Generation	Jackson Site Commons	Routine	Condition-based	GE Long Term Service Agreement FFH	\$ 9,571	\$ 8,908
8	2023	Gas Generation	Jackson Site Commons	Non-Routine	Condition-based	7EA Casing replacement & Hot section overhaul	\$ 2,088	\$ 2,558
9	2023	Gas Generation	Jackson Site Commons	Non-Routine	Condition-based	HRSG Burner Element Isolation Valves Addition	\$ 2,021	\$ 2,210
10	2023	Gas Generation	Zeeland Site Commons	Routine	Condition-based	Long Term Service Agreement - Running Capital Contract	\$ 9,520	\$ 6,657
11	2023	Gas Generation	Zeeland Site Commons	Routine	Condition-based	LTSA - Extras not included in contract (cranes, mobile equipment)	\$ 2,900	\$ 15,184
12	2023	Gas Generation	Zeeland Site Commons	Non-Routine	Condition-based	Zeeland Unit 1 Generator Step Up Transformer Rewind	\$ 4,604	\$ 2,328
13	2023	Gas Generation	Zeeland Site Commons	Non-Routine	Condition-based	Multimedia filtration Pilot Skid		\$ 2,442
14	2023	Gas Generation	Zeeland Site Commons	Non-Routine	Condition-based	Unit 5 generator stepup transformer Rewind		\$ 13,885
15	2023	Gas/Oil Generation	Karn 3	Non-Routine	Condition-based	Cooling Tower Rebuild	\$ 3,971	\$ 5,439
16	2023	Gas/Oil Generation	Karn 3	Non-Routine	Condition-based	Karn 3 Exciter Rewind		\$ 1,039
17	2023	Gas/Oil Generation	Karn Commons	Non-Routine	Condition-based	Boiler Plant Heating Project		\$ 4,836
18	2023	Hydro Generation	Croton	Non-Routine	Condition-based	Croton 1&2 Wicket Gate		\$ 4,330
19	2023	Hydro Generation	Five Channels	Non-Routine	Regulatory	Headgate Project	\$ 1,982	\$ 1,686
20	2023	Hydro Generation	Hardy	Non-Routine	Regulatory	Auxiliary Spillway Remediation	\$ 3,459	\$ 2,591
21	2023	Hydro Generation	Hodenpyl	Non-Routine	Condition-based	Hodenpyl 1 Generator Rewind	\$ 3,101	\$ 3,285
22	2023	Hydro Generation	Hodenpyl	Non-Routine	Condition-based	Spillway Hoist Replacement	\$ 2,864	\$ 2,153
23	2023	Hydro Generation	Ludington Site Commons	Non-Routine	Safety	Replace Lower Penstock Expansion Joint Chamber Waterstop	\$ 2,425	\$ 3,328
24	2023	Hydro Generation	Ludington Site Commons	Non-Routine	Safety	Powerhouse Roof Wearing Surface and Weather Proofing Replacement	\$ 2,724	\$ 2,021
25	2023	Hydro Generation	Mio	Non-Routine	Safety	Electrical Safety Project	\$ 1,086	\$ 2,376
26	2023	Hydro Generation	Rogers	Non-Routine	Condition-based	Unit 4 Generator Rewind	\$ 2,600	\$ 1,965
27	2023	Hydro Generation	Webber	Non-Routine	Infrastructure	Webber Left Downstream Spillway Abutment Wall	\$ 2,975	\$ 3,974
28	2023	Renewables	Solar Commons	Non-Routine	New Generation	Solar - 2021 Bid Event (Muskegon Solar) (250 MW)	\$ 61,930	\$ 58,570
29	Total 2023 Projects						\$ 946,885	\$ 832,335

Note:

(1) Projected amounts were taken from Case No. U-21389

(\$000's)

Date: May 2024

Line No.	(a) Calendar Period	(b) Tier 1 Portfolio	(c) Tier 2 Portfolio	(d) Project Type	(e) Project Classification	(f) Full Internal Budget Approval	(g) Work Item Description	(h) Projected Amount
1	Bridge Period	Gas Generation	Covert	Non-Routine	Condition-based	Approved	Purchase of site spare generator stepup transformer	\$ 1,000
2	Bridge Period	Gas Generation	Covert	Non-Routine	Condition-based	Approved	Cooling Tower Gearboxes	\$ 1,162
3	Bridge Period	Gas Generation	Covert	Routine	Environmental	Approved	SCR/CO Catalyst Replacement - Unit 2	\$ 1,042
4	Bridge Period	Gas Generation	Covert	Routine	Environmental	Approved	SCR/CO Catalyst Replacement - Unit 3	\$ 1,042
5	Bridge Period	Gas Generation	Covert	Routine	Condition-based	Approved	Units 1-3 Emerson DCS Evergreen	\$ 1,041
6	Bridge Period	Gas Generation	Covert	Routine	Condition-based	Approved	Long Term Service Agreement - Running capital contract	\$ 20,400
7	Bridge Period	Gas Generation	Jackson	Routine	Condition-based	Approved	GE LTSA Historical Extra Work Expected	\$ 2,908
8	Bridge Period	Gas Generation	Jackson	Routine	Condition-based	Approved	GE Long Term Service Agreement FFFH	\$ 12,338
9	Bridge Period	Gas Generation	Zeeland	Non-Routine	Condition-based	Approved	Unit 5 generator step up transformer rewind	\$ 5,547
10	Bridge Period	Gas Generation	Zeeland	Non-Routine	Condition-based	Approved	Phase I Gas Turbine Advanced gas path replacement and axial fuel staging	\$ 20,356
11	Bridge Period	Gas Generation	Zeeland	Routine	Condition-based	Approved	LTSA - Extras not included in contract (cranes, mobile equipment)	\$ 3,925
12	Bridge Period	Gas Generation	Zeeland	Routine	Condition-based	Approved	Zeeland Long Term Service Agreement - Running Capital Contract	\$ 9,520
13	Bridge Period	Gas Generation	Zeeland	Non-Routine	Condition-based	Approved	Heat recovery steam generator Casing Replacement	\$ 2,098
14	Bridge Period	Gas/Oil Generation	Karn 3	Routine	Condition-based	Approved	Karn 3 distributed control system Evergreen	\$ 1,507
15	Bridge Period	Gas/Oil Generation	Karn 3	Non-Routine	Condition-based	Approved	Karn 3 Cooling Tower Internal Structure Replacement	\$ 6,000
16	Bridge Period	Gas/Oil Generation	Karn commons	Routine	Condition-based	Approved	Karn 3&4 Sync Wire Replacement	\$ 1,260
17	Bridge Period	Gas/Oil Generation	Karn 3	Routine	Condition-based	Approved	Karn Unit 3 Combustion Air Heater	\$ 2,200
18	Bridge Period	Gas/Oil Generation	Karn 4	Routine	Condition-based	Approved	Karn 4 DCS Evergreen	\$ 1,363
19	Bridge Period	Gas/Oil Generation	Karn commons	Non-Routine	Condition-based	Approved	Boiler Plant Heating Project	\$ 1,760
20	Bridge Period	Hydro Generation	Alcona	Non-Routine	Regulatory	Approved	Alcona Core Wall Remediation Project	\$ 9,025
21	Bridge Period	Hydro Generation	Alcona	Non-Routine	Regulatory	Approved	Alcona Artesian Design Study	\$ 1,358
22	Bridge Period	Hydro Generation	Allegan	Non-Routine	Condition-based	Approved	Allegan 1 Wicket Gate Replacement	\$ 1,900
23	Bridge Period	Hydro Generation	Footo	Non-Routine	Condition-based	Approved	Footo Spillway Hoist Replacement	\$ 1,585
24	Bridge Period	Hydro Generation	Hardy	Non-Routine	Regulatory	Approved	Hardy Auxiliary Spillway Replacement	\$ 2,946
25	Bridge Period	Hydro Generation	Hodenpyl	Non-Routine	Regulatory	Approved	Hodenpyl - Emergency Spillway Project	\$ 1,064
26	Bridge Period	Hydro Generation	Hodenpyl	Non-Routine	Condition-based	Approved	Hodenpyl Spillway Hoist Replacement	\$ 5,108
27	Bridge Period	Hydro Generation	Rogers	Non-Routine	Regulatory	Approved	Rogers Powerhouse Left Embankment Retaining Wall	\$ 2,006
28	Bridge Period	Hydro Generation	Rogers	Non-Routine	Regulatory	Approved	Rogers Probable Maximum Flood Project	\$ 2,466
29	Bridge Period	Hydro Generation	Tippy	Non-Routine	Condition-based	Approved	Tippy - Unit 1 Thrust Bearing Replacement	\$ 1,900
30	Bridge Period	Hydro Generation	Ludington	Non-Routine	Condition-based	Approved	Ludington 1-6 distributed control system Control Relay Replacement	\$ 1,648
31	Bridge Period	Hydro Generation	Ludington	Non-Routine	Condition-based	Approved	Ludington lower penstock expansion joint Chamber water stop replacement	\$ 2,716
32	Bridge Period	Renewables - IRP	Solar	Non-Routine	New Generation	Approved	Solar - 2021 Bid Event (Muskegon Solar) (250 MW)	\$ 141,387
33	Bridge Period	Renewables - IRP	Solar	Non-Routine	New Generation	Approved	Solar - 2022 Bid Event (Spring Creek)	\$ 108,185
34	Bridge Period	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Approved	Armstrong Battery Energy Storage System (IJA Grant App)	\$ 3,931
35	Bridge Period	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Approved	Iosco Battery Energy Storage System (IRP)	\$ 15,990
36	Bridge Period	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Approved	Weadock Battery Energy Storage System (IRP)	\$ 19,751

\$ 419,434

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Summary of Actual and Projected Electric Capital Expenditures
For the years 2023 through 2026
(\$000's)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line No.	Calendar Year	Tier 1 Portfolio	Tier 2 Portfolio	Project Type	Project Classification	Full Internal Budget Approval	Work Item Description	Projected Amount
1	Test Year	Gas Generation	Covert	Non-Routine	Condition-based	Approved	Purchase of site spare GSU	\$ 4,500
2	Test Year	Gas Generation	Covert	Non-Routine	Condition-based	Approved	Cooling Tower Gearboxes	\$ 1,039
3	Test Year	Gas Generation	Covert	Routine	Condition-based	Approved	Units 1-3 Emerson DCS Evergreen	\$ 2,449
4	Test Year	Gas Generation	Covert	Routine	Condition-based	Approved	Long Term Service Agreement - Running capital contract	\$ 14,700
5	Test Year	Gas Generation	Covert	Non-Routine	infrastructure	Approved	Office Space Consumers Energy Warehouse with Loading Dock	\$ 1,817
6	Test Year	Gas Generation	Covert	Routine	Condition-based	Approved	Natmeton (MHPSA Operating System & 4S) - Unit 2	\$ 1,458
7	Test Year	Gas Generation	Covert	Routine	Condition-based	Approved	Natmeton (MHPSA Operating System & 4S) - Unit 3	\$ 1,504
8	Test Year	Gas Generation	Covert	Routine	Condition-based	Approved	Unit 1 - LTSA Capital - Extra work not included in contract	\$ 1,438
9	Test Year	Gas Generation	Covert	Routine	Condition-based	Approved	Unit 2 - LTSA Capital - Extra work not included in contract	\$ 12,610
10	Test Year	Gas Generation	Covert	Routine	Condition-based	Approved	Unit 3 - TSA Capital - Extra work not included in contract	\$ 10,610
11	Test Year	Gas Generation	Jackson	Routine	Condition-based	Approved	G Long Term Service Agreement FFH	\$ 11,117
12	Test Year	Gas Generation	Zeeland	Non-Routine	Condition-based	Approved	Phase I Gas Turbine Advanced gas path replacement and axial fuel staging	\$ 25,744
13	Test Year	Gas Generation	Zeeland	Routine	Condition-based	Approved	LTSA - Extras not included in contract (cranes, mobile equipment)	\$ 4,275
14	Test Year	Gas Generation	Zeeland	Routine	Condition-based	Approved	Long Term Service Agreement - Running Capital Contract	\$ 8,181
15	Test Year	Gas Generation	Zeeland	Non-Routine	Condition-based	Approved	Purchase of Site Spare Generator Step up transformer	\$ 6,449
16	Test Year	Gas Generation	Zeeland	Non-Routine	Condition-based	Approved	Generator Rewinds	\$ 2,174
17	Test Year	Gas Generation	Zeeland	Non-Routine	Condition-based	Approved	Phase II Turbine Replacements	\$ 1,884
18	Test Year	Gas/Oil Generation	Karn	Routine	Condition-based	Approved	Karn 4 Replacement of Ductwork Insulation and Lagging	\$ 4,800
19	Test Year	Gas/Oil Generation	Karn	Non-Routine	Condition-based	Approved	Karn 3&4 Ductwork Expansion Joint Replacement - ID Fans to Stack	\$ 1,900
20	Test Year	Hydro Generation	Fleet	Non-Routine	infrastructure	Approved	Fleet - Build new machine shop	\$ 2,100
21	Test Year	Hydro Generation	Alcona	Non-Routine	Regulatory	Approved	Auxiliary Spillway Improvements	\$ 2,500
22	Test Year	Hydro Generation	Cooke	Non-Routine	Condition-based	Approved	Head Gate Replacement Project	\$ 1,803
23	Test Year	Hydro Generation	Five Channels	Non-Routine	Condition-based	Approved	Five Channels Unit 1 Wicket Gate	\$ 3,753
24	Test Year	Hydro Generation	Five Channels	Non-Routine	Condition-based	Approved	Five Channels Spillway Hoist Replacement	\$ 1,190
25	Test Year	Hydro Generation	Five Channels	Non-Routine	Safety	Approved	Five Channels Trash Rack Ergonomics Project	\$ 1,675
26	Test Year	Hydro Generation	Footo	Non-Routine	Safety	Approved	Footo ADA Ramp Investigation and replacement	\$ 1,463
27	Test Year	Hydro Generation	Hardy	Non-Routine	Regulatory	Approved	Hardy Auxiliary Spillway Replacement	\$ 53,854
28	Test Year	Hydro Generation	Hardy	Non-Routine	Regulatory	Approved	Hardy Splash Wall Replacement	\$ 2,760
29	Test Year	Hydro Generation	Hodenpyl	Non-Routine	Regulatory	Approved	Hodenpyl - Emergency Spillway Project	\$ 1,654
30	Test Year	Hydro Generation	Hodenpyl	Non-Routine	Regulatory	Approved	Hodenpyl Downstream Wall	\$ 3,772
31	Test Year	Hydro Generation	Loud	Non-Routine	Condition-based	Approved	Loud Unit 2 Wicket Gates Replacement	\$ 3,000
32	Test Year	Hydro Generation	Rogers	Non-Routine	Regulatory	Approved	Rogers Probable Maximum Flood Project	\$ 3,207
33	Test Year	Hydro Generation	Tippy	Non-Routine	Safety	Approved	Tippy - Electrical Safety Project	\$ 1,591
34	Test Year	Hydro Generation	Ludington	Non-Routine	Condition-based	Approved	Ludington 1-6 DCS Control Relay Replacement	\$ 4,772
35	Test Year	Hydro Generation	Ludington	Non-Routine	Condition-based	Approved	Ludington Governor Replacement	\$ 1,916
36	Test Year	Hydro Generation	Ludington	Non-Routine	Condition-based	Approved	Ludington 480 Volt Motor Control Centers for DLC	\$ 1,566
37	Test Year	Hydro Generation	Ludington	Non-Routine	Condition-based	Approved	Ludington Intake Gate and Gate House Mechanical Replacement	\$ 1,666
38	Test Year	Hydro Generation	Ludington	Non-Routine	Condition-based	Approved	Ludington Commons Station Power Transformer Life Cycle Management	\$ 1,150
39	Test Year	Renewables - IRP	Solar	Non-Routine	New Generation	Approved	Solar - 2021 Bid Event (Muskegon Solar) (250 MW)	\$ 128,907
40	Test Year	Renewables - IRP	Solar	Non-Routine	New Generation	Approved	Solar - 2022 Bid Event (Spring Creek)	\$ 122,819
41	Test Year	Renewables - IRP	Solar	Non-Routine	New Generation	Approved	Solar - 2020 Bid Event (Washtenaw Solar) (150 MW)	\$ 24,233
42	Test Year	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Approved	Armstrong Battery Energy Storage System (IIJA Grant App)	\$ 4,878
43	Test Year	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Approved	Iosco Battery Energy Storage System (IRP)	\$ 29,867
44	Test Year	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Approved	Weadock Battery Energy Storage System (IRP)	\$ 44,176
45	Total Test Year Projects							\$ 568,922

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Generating Unit Availability Projections
March 1, 2025 Through February 28, 2026

Case No.: U-21585
Exhibit No.: A-42 (RTB-2)
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	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Plant	Actual ROR 2019-2023	Projected ROR	Periodic Factor	Projected Availability	Actual NEV 2019-2023
1	Campbell 1	16.89%	16.00%	66.30%	28.30%	\$94,251,307
2	Campbell 2	30.27%	15.00%	0.00%	85.00%	\$83,293,257
3	Campbell 3	14.29%	8.00%	0.00%	92.00%	\$347,202,422
4	Karn 3	38.70%	18.00%	11.78%	72.34%	-\$8,065,128
5	Karn 4	24.76%	18.00%	12.88%	71.44%	-\$10,424,299
6	Ludington 1	5.06%	3.50%	10.96%	85.92%	\$19,165,396
7	Ludington 2	4.94%	3.50%	8.49%	88.30%	\$454,083
8	Ludington 3	6.81%	3.50%	18.36%	78.79%	-\$57,815
9	Ludington 4	7.75%	3.50%	18.36%	78.79%	-\$298,851
10	Ludington 5	7.34%	3.50%	23.29%	74.03%	\$1,941,254
11	Ludington 6	4.97%	3.50%	20.00%	77.20%	\$16,330,522
12	Hydros	9.48%	5.60%	16.14%	79.16%	\$47,444,888
13	Zeeland CC	7.48%	4.00%	12.60%	83.90%	\$183,763,696
14	Zeeland 1A	3.89%	4.00%	9.59%	86.79%	\$16,822,762
15	Zeeland 1B	4.45%	4.00%	9.59%	86.79%	\$19,956,480
16	Jackson	8.22%	4.50%	14.52%	81.63%	\$158,401,855
17	Covert 1	4.09%	7.00%	13.15%	80.77%	\$17,911,397
18	Covert 2	6.25%	7.00%	11.23%	82.55%	\$13,462,508
19	Covert 3	6.08%	7.00%	19.18%	75.16%	\$17,995,020
20	Cross Winds EP					\$123,677,013
21	Lake Winds EP					\$43,059,634
22	Gratiot Farms Wind ⁽²⁾					\$34,390,807
23	Crescent Wind ⁽²⁾					\$34,096,348
24	Heartland ⁽³⁾					\$425,801
25	Solar Gardens ⁽¹⁾					\$1,140,655

- (1) Reflects NEV for 2020-2023 only.
(2) Reflects NEV for 2022-2023 only.
(3) Reflects NEV for 2023 only.

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
 Summary of the Generation O&M Expense
 For the Years 2023 through February 2026
 (\$000's)

Case No.: U-21585
 Exhibit No.: A-43 (RTB-4)
 Page: 1 of 3
 Witness: RTBlumenstock
 Date: May 2024

GENERATION OPERATION AND MAINTENANCE EXPENSES

Line No.	(a) Description	(b) Historical 12 Months Ended 12/31/2023		(c) Projected Bridge Period 14 Months Ending 02/28/2025		(d) Projected Test Year 12 Months Ending 02/28/2026	
1	BASE O&M	\$	93,864	\$	121,165	\$	78,063
2	ADJUSTED O&M						
3	Environmental Operations	\$	9,225	\$	6,965	\$	2,584
4	Major Maintenance	\$	15,759	\$	37,035	\$	31,203
5	Retention & Separation	\$	17,348	\$	11,158	\$	4,621
6	TOTAL O&M		118,848.652		165,164.491		111,850.689

(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	Description	2023 Actual	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2023	Merit & Inflation 12 Mos Ending Dec 31, 2024	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2024	Merit & Inflation 12 Mos Ending Dec 31, 2025	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2025	Merit & Inflation 2 Mos Ending 2/28/2026	Other Adjustments	Projected O&M 12 Mos Ending 2/28/2026
				(c) * Inflation Rate		(e) * Inflation Rate		(g) * Inflation Rate		(b) + (d) + (f) + (h) + (i)
	Total O&M	118,849	118,849	2,852	121,701	2,677	124,378	456	-12,083	111,851
1	Labor	74,659	74,659	1,792	76,451	1,682	78,133	286	-8,156	70,264
2	Material	5,604	5,604	134	5,738	126	5,865	22	7,742	13,628
3	Contractor	14,481	14,481	348	14,828	326	15,154	56	-9,936	5,274
4	Non-Labor Overheads	0	0	0	0	0	0	0	0	0
5	Non-Labor Other	24,105	24,105	579	24,683	543	25,226	92	-2,633	22,685

Notes		2024	2025	2026
* Annual merit increase	Annual merit increase	2.4%	2.2%	2.2%
	Number of months in the period	12	12	2
	Pro-rated merit increase	2.4%	2.2%	0.4%
Annual inflation rates per WP-JCA-51	Annual inflation rates	2.4%	2.2%	2.2%
	Number of months in the period	12	12	2
	Pro-rated inflation rate	2.4%	2.2%	0.4%

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Summary of the Generation Major Maintenance O&M Expense
For the Years 2023 through February 2026
(\$000's)

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Exhibit No.: A-43 (RTB-4)
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Witness: RTBlumenstock
Date: May 2024

GENERATION MAJOR MAINTENANCE EXPENSES

Line No.	(a) Description	(b) Historical 12 Months Ended 12/31/2023		(c) Projected Bridge Period 14 Months Ending 02/28/2025		(d) Projected Test Year 12 Months Ending 02/28/2026	
	Major Maintenance						
1	Campbell 1&2	\$	1,054	\$	2,189	\$	268
2	Campbell 3	\$	995	\$	2,413	\$	277
3	Karn 1&2	\$	67	\$	202	\$	100
4	Karn 3&4	\$	216	\$	2,314	\$	2,502
5	Classic 7	\$	52	\$	264	\$	218
6	Zeeland Generating Station	\$	3,121	\$	5,959	\$	5,232
7	Jackson Generating Station	\$	2,822	\$	5,256	\$	3,852
8	Covert Generating Stations	\$	2,144	\$	5,919	\$	7,706
9	Ludington	\$	2,533	\$	4,924	\$	4,445
10	Hydros	\$	2,756	\$	6,990	\$	5,776
11	Solar	\$	-	\$	432	\$	677
12	Admin & Other	\$	-	\$	175	\$	150
13	TOTAL Major Maintenance	\$	15,759	\$	37,035	\$	31,203

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Midcontinent)
Independent System Operator)
(MISO))

Order No. 202-26-16

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 12

Blumenstock 2025 Direct
Testimony

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21870

DIRECT TESTIMONY

OF

RICHARD T. BLUMENSTOCK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

RICHARD T. BLUMENSTOCK
U-21870 DIRECT TESTIMONY

1 **Q. Please state your name and business address.**

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

4 **Q. By whom are you employed?**

5 A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”).

6 **Q. What is your position with Consumers Energy?**

7 A. I am currently the Executive Director of Electric Supply Engineering. I began employment
8 at the Company in May 1994 in the electric transmission planning area where I performed
9 planning studies on the Company’s distribution and transmission systems. In April 2002,
10 I was assigned to the electric operations area where I oversaw engineering operations for
11 the distribution and transmission systems. In August 2009, I was assigned to the fuel
12 supply area where I oversaw the Company’s purchasing and transport functions for fuel
13 for electric generation. In June 2011, I assumed additional responsibilities including
14 oversight of the Company’s interaction in the Midcontinent Independent System Operator,
15 Inc. (“MISO”) markets; wholesale settlements and transactions functions; Power Supply
16 Cost Recovery (“PSCR”) activities; and planning for electric supply necessary to satisfy
17 customers’ energy and capacity needs. In September 2019, I assumed the role of Executive
18 Director of Electric Planning, overseeing the company-wide efforts for all electric
19 planning. In September 2022, I assumed my current position as Executive Director of
20 Electric Supply Engineering.

RICHARD T. BLUMENSTOCK
U-21870 DIRECT TESTIMONY

1 **Q. What are your responsibilities as Executive Director of Electric Supply Engineering?**

2 A. My responsibilities as Executive Director of Electric Supply Engineering include oversight
3 of all activities associated with planning and design for the Company's electric generation
4 portfolio.

5 **Q. What is your formal educational experience?**

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

8 **Q. Have you previously provided testimony before the Michigan Public Service
9 Commission ("MPSC" or the "Commission")?**

10 A. Yes, I provided testimony in the following MPSC cases:

- 11 • Case No. U-16045-R: Reconciliation of PSCR Costs and Revenues for the
12 Calendar Year 2010;
- 13 • Case No. U-16432-R: Reconciliation of PSCR Costs and Revenues for the
14 Calendar Year 2011;
- 15 • Case No. U-16890: Approval of a PSCR Plan and for Authorization of Monthly
16 PSCR Factors for the Year 2012;
- 17 • Case No. U-16890-R: Reconciliation of PSCR Costs and Revenues for the
18 Calendar Year 2012;
- 19 • Case No. U-17429: Approval of a Certificate of Necessity for the Thetford
20 Generating Plant pursuant to MCL 460.6s and for related accounting and
21 ratemaking authorizations;
- 22 • Case No. U-17317: Approval of a PSCR Plan and for Authorization of Monthly
23 PSCR Factors for the Year 2014;
- 24 • Case No. U-17317-R: Reconciliation of PSCR Costs and Revenues for the
25 Calendar Year 2014;
- 26 • Case No. U-17752: Authority to amend its renewable energy plan approved in
27 Case Nos. U-15805, U-16543, U-16581, and U-17301;
- 28 • Case No. U-17678: Approval of a PSCR Plan and for Authorization of Monthly
29 PSCR Factors for the Year 2015;

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- Case No. U-17678-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2015;
- Case No. U-18250: Application of Consumers Energy for a financing order approving the securitization of qualified costs and related approvals associated with the early termination of the Palisades Nuclear Energy Plant Power Purchase Agreement;
- Case No. U-20134: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief;
- Case No. U-20165: Application of Consumers Energy for approval of its Integrated Resource Plan (“IRP”) pursuant to MCL 460.6t and for other relief;
- Case No. U-20697: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief;
- Case No. U-20963: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief;
- Case No. U-21090: Application of Consumers Energy for Approval of an IRP under MCL 460.6t, certain accounting approvals, and for other relief;
- Case No. U-21224: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief;
- Case No. U-21389: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief; and
- Case No. U-21585: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief.

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

A. The purpose of my direct testimony is to support the Generation Department (“Generation”) requests in this case, and to provide other information that the Company has committed to provide. Toward that end I will:

- Describe Consumers Energy’s oil-, and gas-fired generation assets, and its hydroelectric and renewable generation assets, including their projected retirement dates;
- Support the Company’s generation asset strategy to focus continued investment in those generating units (Zeeland Generating Station (“Zeeland Plant”, “ZGS” or “Zeeland”), New Covert Generating Facility (“Covert Plant” or “Covert”),

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and Jackson Generating Station (“Jackson Plant”, “JGS” or “Jackson”)) which provide the most long-term economic benefit for customers;

- Support the periodic outage plans and the Generation Unit Availability and Random Outage Rate (“ROR”) projections for oil- and gas-fired peaking generation, and hydroelectric power generation, for the projected test year ending April 30, 2027;
- Support the reasonableness and prudence of the capital expenditures for oil- and gas-fired peaking generation, and hydroelectric power generation for the historical test year ended December 31, 2024, the 16-month bridge period beginning January 1, 2025 and ending April 30, 2026, and the projected test year ending April 30, 2027;
- Support the reasonableness and prudence of the Operation and Maintenance (“O&M”) oil- and gas-fired peaking generation, and hydroelectric power for historical test year ended December 31, 2024, the 16-month bridge period beginning January 1, 2025 and ending April 30, 2026, and the projected test year ending April 30, 2027;
- Support the reasonableness and prudence of the O&M expenses for the D.E. Karn (“Karn”) Units 1 and 2 retention and separation incentives for the historical test year ended December 31, 2024;
- Support the reasonableness and prudence of the O&M expenses for the J.H. Campbell (“Campbell”) Units 1, 2, and 3 retention and separation incentives for the historical test year ended December 31, 2024, and the 16-month bridge period beginning January 1, 2025 and ending April 30, 2026;¹ and
- Describe the environmental regulations with which the Company’s electric generating fleet must comply.

Q. How is your direct testimony related to the direct testimony of other Company witnesses?

A. Company witness Megan L. Metz’s testimony supports the PSCR costs planned to be incurred, taking into account the periodic outages identified in Exhibit A-41 (RTB-1) and

¹ On May 23, 2025, the U.S. Department of Energy issued Order No. 202-25-3 (“DOE Order”) requiring the Company to “take all measures necessary to ensure that the Campbell Plan is available to operate” through August 21, 2025. The DOE Order also specifies that, at the conclusion of this period, the Company will be permitted “sufficient time for orderly ramp down . . . consistent with industry practices.” The Company is currently evaluating the impact of the DOE Order on its decommissioning plan and other aspects of this rate case. Until the Company is able to complete its evaluation, my testimony continues to reflect assumptions about the Campbell Plant’s retirement before the date of the DOE Order.

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the generating unit availability projections in Exhibit A-42 (RTB-2). Company witness Metz also supports the capacity value of the Company's generation assets for the seasonal construct in the MISO Planning Resource Auction ("PRA") in Table 2.

Company witness Thomas P. Clark supports the competitive solicitation process and timeline associated with the proposed battery energy storage system ("BESS") projected capital expenditures.

Company witness Patrick D. Daly supports the regulatory asset balances and amortization for the recovery of retention and separation expenses at Karn and Campbell sites in his direct testimony.

Company witness Heidi J. Myers supports the continued deferral of the revenue requirement for river hydroelectric generating plant ("River Hydro") capital expenditures as well as the proposed O&M deferral for River Hydro in her direct testimony.

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

A. Yes, I am sponsoring the following exhibits:

Exhibit A-41 (RTB-1)	Generating Unit Periodic Outages;
Exhibit A-42 (RTB-2)	Generating Unit Availability Projections;
Exhibit A-12 (RTB-3) Schedule B-5.2	Summary of Actual and Projected Electric Capital Expenditures for the Years 2024 through April 2027;
Exhibit A-43 (RTB-4)	Summary of the Generation O&M Expense for the Years 2024 through February 2027;
Exhibit A-44 (RTB-5)	Zeeland Phase I and II Gas Turbine Upgrade Concept Approvals;
Exhibit A-45 (RTB-6)	Jackson Site Spare GSU Transformer Concept Approval;

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1	Exhibit A-46 (RTB-7)	Covert Load Commutated Inverter
2		Static Frequency Converter
3		Replacements Concept Approval;
4	Exhibit A-47 (RTB-8)	Covert Site Spare GSU Transformer
5		Concept Approval;
6	Exhibit A-48 (RTB-9)	Covert Control System Project
7		Concept Approval;
8	Exhibit A-49 (RTB-10)	Covert Units 1 through 3 Emerson
9		DCS Evergreen Concept Approval;
10	Exhibit A-50 (RTB-11)	Karn Unit 4 ID Fan Inlet Damper
11		Replacements Concept Approval;
12		and
13	Exhibit A-51 (RTB-12)	Karn Units 3 & 4 Combustion Air
14		Heater Replacement Concept
15		Approval.

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

17 A. Yes.

18 **Q. How are the following sections of your direct testimony organized?**

19 A. My direct testimony is divided into four sections. Section I will present exhibits and
20 supporting testimony on the Company's generating assets, its generating asset strategy, and
21 its generating asset projected performance metrics. Included in this section is a discussion
22 on the status of the Company's River Hydro strategy and its projected impact on the
23 Company's cost projections. Section II will describe the environmental regulations with
24 which the Company's electric generating fleet must comply. Section III presents exhibits
25 and supporting testimony for the historical and projected generation capital expenditures.
26 Section IV will present exhibits and supporting testimony for the historical and projected
27 generation O&M expense. This section will include support of the reasonableness and
28 prudence of the O&M expenses for both the Karn Units 1 and 2 retention and separation

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incentives, the reasonableness and prudence of the O&M expenses for Campbell Units 1, 2, and 3 retention and separation incentives, and the Company's proposal for River Hydro O&M expense.

SECTION I

GENERATION ASSETS

Q. Please provide an overview of the Company's generation assets.

A. As of February 24, 2025, the Company's total projected owned generation assets for the 2025/2026 Planning Year had a Generator Verification Test Capacity ("GVTC") of 5,722 MW, comprised of the following units:

TABLE 1

RESOURCE	MICHIGAN LOCATION	IN-SERVICE DATE	AGE (years)	RETIREMENT DATE	NET GENERATING CAPABILITY (MW)
OIL OR GAS FIRED					
Covert	Covert, MI	2004	21	2040	1090
DE Karn 3	Essexville, MI	1975	50	2031	602
DE Karn 4	Essexville, MI	1977	48	2031	587
Zeeland CC	Zeeland, MI	2002	23	2041	534
Zeeland 1A	Zeeland, MI	2002	23	2041	158
Zeeland 1B	Zeeland, MI	2002	23	2041	157
Jackson	Jackson, MI	2002	23	2041	531
HYDROELECTRIC					
Alcona	Alcona County, MI	1924	101	n/a	3
Allegan	Allegan County, MI	1936	89	n/a	1
Cooke	Iosco County, MI	1911	114	n/a	7
Croton	Newaygo County, MI	1907	118	n/a	2
Five Channels	Iosco County, MI	1912	113	n/a	6
Foote	Iosco County, MI	1918	107	n/a	3
Hardy	Newaygo County, MI	1931	94	n/a	33
Hodenpyl	Wexford County, MI	1925	100	n/a	4
Loud	Iosco County, MI	1913	112	n/a	5
Mio	Oscoda County, MI	1916	109	n/a	1
Rogers	Mecosta County, MI	1906	119	n/a	2
Tippy	Manistee County, MI	1918	107	n/a	6
Webber	Ionia County, MI	1907	118	n/a	1
RENEWABLES					
Lake Winds	Mason County, MI	2012	13	2042	101
Cross Winds (Phase I)	Tuscola County, MI	2014	11	2044	231
Cross Winds (Phase II)	Tuscola County, MI	2018	7	2048	
Cross Winds (Phase III)	Tuscola County, MI	2018	7	2048	
Crescent Wind	Jonesville, MI	2021	4	2051	166
Gratiot Farms Wind	Alma, MI	2021	4	2051	150
Heartland Farms Wind Park	Ithaca, MI	2024	1	2054	200
Solar Gardens- GVSU	Grand Rapids, MI	2016	9	2046	3
Solar Gardens- WMU	Kalamazoo, MI	2016	9	2046	1
Cadillac Solar Garden	Cadillac, MI	2021	4	2051	0.5
Circuit West	Grand Rapids, MI	2019	6	2049	0.5
ENERGY STORAGE					
Ludington Units 1-6**	Ludington, MI	1973	52	2069	1138 (owned share)

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1 **Q. What does “owned share” mean when used with respect to Ludington Pumped**
2 **Storage Plant (“LPS” or “Ludington”) Units 1 through 6?**

3 A. The Company owns 51% of LPS and DTE Electric Company (“DTE”) owns the remaining
4 49%. Thus, the 1,138 MW capacity reported is 51% of the total LPS GVTC, reflecting the
5 Company’s share of ownership.

6 **Q. Do any of the Company’s owned generation units reflect retirement dates which are**
7 **different from those sponsored in the Company’s previous Electric Rate Case, Case**
8 **No. U-21585?**

9 A. No. There have been no changes to the retirement dates for the Company’s owned
10 generation units. The only change to the Company’s owned generation units was the
11 retirement of Campbell Units 1, 2 and 3 on May 31, 2025.

12 **Q. How will the Company continue to meet its load requirements with the retirement of**
13 **the Campbell units?**

14 A. The Settlement Agreement approved in the Company’s 2021 IRP reflects the replacement
15 of the Campbell unit capacity through a number of different resources including continued
16 growth of its solar generation assets, demand response, energy waste reduction, the
17 acquisition of the Covert Plant on June 1, 2023, continued operation of Ludington and Karn
18 Units 3 and 4, and the addition of Zonal Resource Credits (“ZRCs”) by June 1, 2025,
19 through a one-time solicitation approved as part of the Settlement Agreement.

20 **Q. What capacity resources were identified through the one-time solicitation?**

21 A. The IRP one-time solicitation resulted in the execution of 3 separate contracts totaling
22 400 MW of BESS projects. The Company’s January 12, 2024, filing of the Tibbits Energy
23 Storage, LLC Power Purchase Agreement (“PPA”), a 100-MW battery storage project

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1 which the MPSC approved in its April 11, 2024 Order. The term of the PPA is 20 years,
2 with deliveries expected to commence by May 31, 2025 with an expected PPA termination
3 date of May 31, 2045. The IRP one-time solicitation also resulted in the Company's
4 May 13, 2024 filing of the Century Oaks Energy Storage LLC PPA, a 200-MW battery
5 storage energy project. The Century Oaks Energy Storage LLC PPA also has a term of
6 20 years with deliveries expected to commence by May 31, 2026, and an expected PPA
7 termination date of May 31, 2046. Finally, the IRP one-time solicitation resulted in the
8 Company's September 27, 2024, filing of the Voyager Energy Storage LLC PPA, a
9 100-MW battery storage project which the MPSC approved in its November 21, 2024
10 Order. The Voyager Energy Storage LLC PPA also has a term of 20 years and, with
11 deliveries expected to commence by May 31, 2027, with an expected PPA termination date
12 of May 31, 2047. Each of these contracts were filed in MPSC Case No. U-21090.

13 **Q. What other actions has the Company taken to ensure it has sufficient capacity to**
14 **reliably serve its customers?**

15 A. In addition to the 400 MW of BESS PPAs, the Company has executed several agreements
16 with Midland Cogeneration Venture ("MCV") for short-term capacity measured in ZRCs.
17 On November 21, 2024, in Case No. U-21666, the Company received MPSC approval of
18 a contract for 100 ZRCs for the 2025, 2026, and 2027 planning years. On March 21, 2025,
19 in Case No. U-21827, the Company received MPSC approval of a contract for 175 ZRCs
20 for the 2025 and 2026 planning years. The contract was the result of a reverse capacity
21 auction that was conducted by an independent administrator on July 18, 2024.

GENERATION ASSET STRATEGY

Q. Please describe the Company's asset strategy for its generating units.

A. The Company's generation asset strategy is focused on delivering safe, reliable, affordable, and clean energy and capacity for its customers. This strategy will be implemented within the construct of the Company's clean energy goals and its IRPs and renewable energy plans, as approved by the MPSC.

Q. How does the Company's generation asset strategy apply to the Company's various generating units?

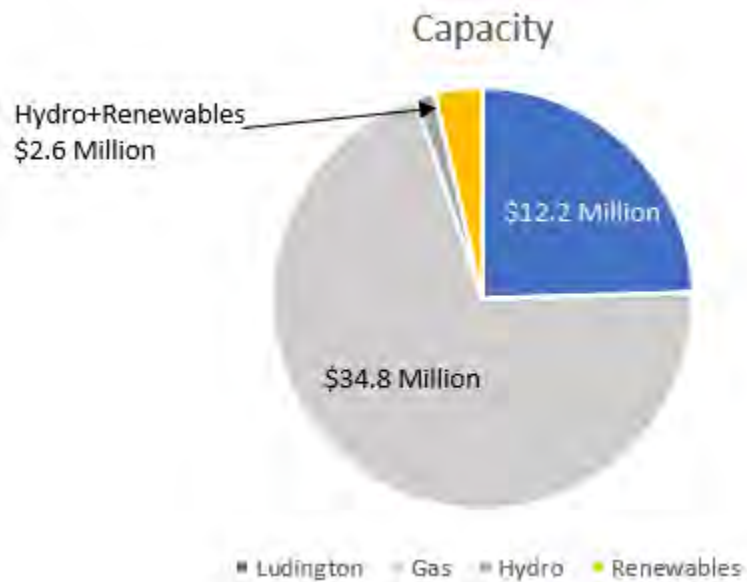
A. Consistent with Consumers Energy's strategy, the Company's generating asset investments will focus on onboarding renewable energy resources, including BESSs as well as those generating assets that provide the most economic benefit to customers through their energy and capacity value in the respective MISO markets. In addition, the Company will also ensure it complies with all state and federal regulations.

Consistent with the approval of the Company's Proposed Course of Action ("PCA") in its 2021 IRP and the Company's 2024 Amended Renewable Energy Plan, the Company will concentrate investment in new renewable energy resources and continue investment in the existing gas-fired units as this strategy will provide the greatest long-term customer benefit. During 2024, the Company's Covert, Zeeland and Jackson Plants produced over 70% of the net energy value and approximately 56% of the capacity value realized by the Company's electric generating fleet (excluding renewables). As such, the Company's investment focus and associated performance projections have been correspondingly set for these generating units. The figures below reflect the 2024 net energy and capacity value by asset type:

FIGURE 1



FIGURE 2



1 **Q. How does the Company's generation asset strategy apply to the balance of the**
2 **Company's generating units?**

3 A. The Company's generation asset strategy with respect to the remaining generating units
4 will vary depending on each unit's energy value, capacity value, and consistency with the
5 Company's currently approved IRP expected retirement dates. The Company will continue
6 to maintain its generating units, including the River Hydro facilities, to ensure safe and
7 environmentally compliant operations. I will provide additional detail regarding the
8 Company's generation asset strategy for each of the generating units, or group of
9 generating units, in the portion of this direct testimony describing projected generating unit
10 availability.

11 **Q. Has the Company's existing generation asset strategy changed as a result of the 2023**
12 **Michigan energy legislation?**

13 A. Not materially. While Public Act ("PA") 235 of 2023 requires the Company to achieve a
14 50% renewable portfolio standard ("RPS") by 2030, the Company had already committed
15 to an aggressive transition in its generation asset portfolio mix through its 2018 and 2021
16 IRPs. Pursuant to PA 235 of 2023, the Company filed a Renewable Energy Plan
17 amendment on November 15, 2024, which reflected its plans to comply with the new
18 renewable energy laws.

19 With respect to the clean energy portion of the 2023 Michigan energy legislation,
20 the details for the Company's compliance with the clean energy portfolio targets contained
21 in that legislation will be reflected in the Company's proposed course of action in its next
22 IRP to be filed in 2026.

**PERIODIC OUTAGE PLANS, AVAILABILITY, ROR PROJECTIONS,
AND NET ENERGY VALUE**

Q. Please describe Exhibit A-41 (RTB-1).

A. Exhibit A-41 (RTB-1) identifies the major outages (28 days or longer in duration) that are scheduled during the projected test year ending April 30, 2027 for the Company's fossil-fueled and Ludington Generating Units. The Company's generation asset strategy is a key input to the scheduling of planned outages, and outage duration directly informs the periodic factors ("PFs") reflected on Exhibit A-42 (RTB-2).

Q. Please describe Exhibit A-42 (RTB-2), Generating Unit Availability Projections.

A. Exhibit A-42 (RTB-2) details Generating Unit Availability Projections for Consumers Energy's peaking generation, and hydraulic power generation for the projected test year beginning May 1, 2026 and ending April 30, 2027. Column (a) identifies Consumers Energy's generating units or category of generating units. Column (b) identifies the five-year historical ROR of the generating unit or category of generating unit. Column (c) identifies the projected ROR of the unit or category of generating unit. Column (d) identifies the PF of the generating unit or category of generating unit. Column (e) identifies the projected availability of the generating unit or category of generating unit. Column (f) identifies the five-year historical Net Energy Value ("NEV") of the generating unit or category of generating unit.

Q. Please define ROR.

A. ROR is a measure of the percent of MWh unavailability due to forced or unplanned generating unit outages and forced or unplanned generating unit de-rates.

1 **Q. What factors cause an increase or decrease in ROR?**

2 A. The frequency and/or duration of a forced or unplanned generating unit outage or
3 generating unit de-rate directly affects ROR. Reducing the frequency and/or duration of
4 forced or unplanned generating unit outages and generating unit de-rates decreases ROR.
5 Conversely, increasing the frequency and/or duration of forced or unplanned generating
6 unit outages and generating unit de-rates degrades ROR.

7 **Q. How are ROR projections for the Generating units developed?**

8 A. The ROR projections for the projected test year ending April 30, 2027 were developed
9 from the five-year (2020-2024) average. These five-year averages were then adjusted to
10 reflect current operating conditions and projected unit investment. The projected unit
11 investment is developed in accordance with the Company's generation asset strategy.
12 These five-year historical ROR average values are presented in Exhibit A-42 (RTB-2),
13 column (b).

14 **Q. Please define PF.**

15 A. PF is a measure of the percent of lost availability that results from planned outages, planned
16 outage extensions, planned de-rates, and planned de-rate extensions. Planned derates can
17 be taken for a variety of reasons, including the performance of necessary maintenance work
18 which does not require an outage to perform, or the management of emissions at gas
19 generation facilities to stay within environmental limits.

20 **Q. What strategy does the Company employ to minimize the impact of planned outages**
21 **on its customers?**

22 A. Consistent with the Company's generation asset strategy, the Company endeavors to
23 schedule planned generating unit outages during periods in which the margin between the

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1 generating unit production cost and the projected MISO energy market price is lowest.
2 This strategy results in creating greater total NEV as I will discuss in more detail later in
3 this direct testimony. In general, the projected MISO energy market pricing is lower in the
4 shoulder months of spring and fall due to historically lower demand. However, with the
5 introduction of seasonal capacity in the MISO market, the Company will also consider the
6 impact of outage scheduling on capacity accreditation for the four capacity seasons.
7 Company witness Metz describes seasonal capacity in more detail in her testimony.

8 **Q. Please define Projected Availability.**

9 A. Projected Availability is a measure of the percent of time that a generating unit or category
10 of generating units is projected to be available to generate electricity.

11 **Q. How is Projected Availability determined for each generating unit or category of**
12 **generating units?**

13 A. The Projected Availability for each generating unit or category of generating unit is
14 calculated as $(100\% - PF) * (100\% - ROR)$. Projected Availability is the key performance
15 metric for implementation of the Company's generation asset strategy for each generating
16 unit or category of generating unit.

17 **Q. How does the Company's generation asset strategy inform Projected Availability?**

18 A. As I previously discussed, the Company's generation asset strategy and associated
19 generation investment will focus on each unit's ability to provide economic value to
20 customers through the unit's ability to produce energy and capacity value in the respective
21 MISO markets. As such, those generating units or category of generating unit providing
22 the greatest amount of economic value to customers will be targeted to achieve the highest
23 projected availabilities.

1 **Q. How can the Company impact Projected Availability for a generating unit?**

2 A. The Company can directly impact Projected Availability for a generating unit by
3 minimizing both PF and ROR for that unit. With respect to minimizing PF, the Company
4 can employ incremental resources during a planned outage to ensure that the critical path
5 for the outage is as short as possible. This strategy could include working 24-hours, seven
6 days a week, for the duration of the outage. Similarly, when a unit experiences an
7 unplanned outage, the Company can employ necessary resources to ensure the unit is
8 returned to available status as quickly as practical. In addition to minimizing unforced
9 outage length, the Company could invest in a generating unit to increase its reliability and,
10 as a result, decrease the generating unit's projected ROR.

11 **Q. Does the Company attempt to maximize availability for all its generating units or**
12 **category of generating units?**

13 A. No. Consistent with the Company's generation asset strategy, the Company focuses on
14 sustaining availability for those generating units which provide the greatest economic
15 benefit to customers through the energy value provided. The Company's generating units
16 get dispatched by MISO as part of the MISO energy market. Based upon the Company's
17 projected dispatch likelihood for each unit, the Company will rank the generating units
18 from highest economic value to least economic value, and manage the PF and the ROR,
19 and therefore the unit's Availability, to allow for the highest customer value. Or, stated
20 differently, the PF and ROR values may be allowed to be higher (lower unit Availability)
21 for the lower economic value units, and will be managed to lower values (higher unit
22 Availability) for higher economic value units.

1 **Q. How does the Availability projection reflect the customer benefit?**

2 A. An improvement in Availability can translate to a customer benefit in several ways. The
3 immediate benefit is that the generating unit or the category of generating unit is available
4 for dispatch for a greater number of hours throughout the year, likely leading to increased
5 generation, and consequently higher NEV, on an annual basis. Additionally, higher
6 availability increases the ZRCs, increasing the capacity value of the unit.

7 **Q. How does the Company measure the customer benefit resulting from increased**
8 **generation?**

9 A. The Company utilizes NEV to quantify this customer benefit. At a high level, NEV of a
10 generating unit is the difference between the market value of energy and the cost of
11 producing and supplying that energy. NEV is the net customer benefit of a generator's
12 energy production expressed in dollars. These values are presented in Exhibit A-42
13 (RTB-2), column (f), which identifies five-year (2020-2024) actual NEV amounts.

14 **Q. What can the Company do to positively affect NEV?**

15 A. Typically, economic investments that improve the reliability and availability of the
16 generating unit or category of unit will result in increasing NEV. Economic investments
17 that result in a reduction in the cost to generate will also result in increasing NEV, all else
18 being equal. Positive NEV increases when a generating unit operates more frequently
19 during periods in which market pricing exceeds the cost of production for that unit.
20 Historically, market pricing has tended to be higher in the summer and winter, although
21 there is variability to market conditions. As discussed earlier in my testimony, this is the
22 reason that periodic outages are generally scheduled in the shoulder months of spring and

1 fall. Market prices are typically lower during this time period, thereby reducing the PSCR
2 impact of each scheduled outage.

3 **Q. Does the cost of production vary for the Company's generating units?**

4 A. Yes. The basis for the Company's generation asset strategy is directly related to this
5 actuality. The Company's investment strategy is focused on those units with the lowest
6 variable production costs to maximize NEV for its customers. As the Company
7 strategically invests additional funds in a generating unit to increase its reliability, the
8 expectation is for the generating unit's reliability to be higher than otherwise possible
9 absent the investment. Higher reliability, in turn, increases the likelihood the unit is
10 available during periods when market prices exceed the production cost of the unit, thus
11 increasing the NEV of the unit.

12 **Q. Why is the measurement of NEV important to the Company and its customers?**

13 A. Positive NEV reflects a direct and immediate reduction to customer power supply costs
14 and consideration of NEV provides a basis for making operational and financial decisions
15 in order to maximize the customer value of the generating unit.

16 **Q. What is another measure the Company uses to evaluate economic projects for its
17 generating units?**

18 A. In addition to measuring NEV for a generating unit, the Company also considers the impact
19 a higher availability (specifically ROR) will have on the amount of capacity available from
20 a particular generating unit which receives a monetary credit in the MISO Resource
21 Adequacy Market. Table 2 below summarizes the current capacity value of the Company's
22 generating units based upon the summer season results in the 2024-2025 PRA for Zone 7.
23 Company witness Metz discusses the capacity value of the Company's generating units in

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the PRA in her testimony in this case. I will discuss the projected impact of the Company's generation asset strategy and associated capital expenditures and major maintenance on the projected availabilities, NEV, and capacity value for each of the generating units later in this direct testimony.

TABLE 2

RESOURCE	MICHIGAN LOCATION	MISO ISAC ¹ MW	MISO SUMMER SAC ² MW (ZRCs)	CAPACITY VALUE ZONE 7 (SETTLEMENT) ³	CAPACITY VALUE ZONE 7 (75% CONE) ⁴
OIL OR GAS FIRED					
Covert	Covert, MI	1089.5	952.9	\$ 10,434,255	\$ 70,178,191
DE Karn 3	Essexville, MI	602.1	367	\$ 4,018,650	\$ 27,028,435
DE Karn 4	Essexville, MI	586.8	542.3	\$ 5,938,185	\$ 39,938,748
Zeeland CC	Zeeland, MI	533.8	501.5	\$ 5,491,425	\$ 36,933,952
Zeeland 1A	Zeeland, MI	157.6	153.3	\$ 1,678,635	\$ 11,290,079
Zeeland 1B	Zeeland, MI	156.7	153	\$ 1,675,350	\$ 11,267,985
Jackson	Jackson, MI	531	508.6	\$ 5,569,170	\$ 37,456,845
HYDROELECTRIC					
Alcona	Alcona County, MI	2.7	2.7	\$ 29,565	\$ 198,847
Allegan	Allegan County, MI	1.2	1.2	\$ 13,140	\$ 88,376
Cooke	Iosco County, MI	7.2	6.8	\$ 74,460	\$ 500,799
Croton	Newaygo County, MI	2.1	2.1	\$ 22,995	\$ 154,659
Five Channels	Iosco County, MI	6.2	5.8	\$ 18,615	\$ 427,152
Footte	Iosco County, MI	2.7	2.8	\$ 30,660	\$ 206,211
Hardy	Newaygo County, MI	33.3	32.4	\$ 354,780	\$ 2,386,162
Hodenpyl	Wexford County, MI	4.1	4.1	\$ 44,895	\$ 301,953
Loud	Iosco County, MI	5	4.8	\$ 52,560	\$ 353,505
Mio	Oscoda County, MI	1.3	1.3	\$ 14,235	\$ 95,741
Rogers	Mecosta County, MI	2	2.1	\$ 22,995	\$ 154,659
Tippy	Manistee County, MI	5.8	5.8	\$ 63,510	\$ 427,152
Webber	Ionia County, MI	1	1	\$ 10,950	\$ 73,647
RENEWABLES					
Lake Winds	Mason County, MI	100.8	17.9	\$ 196,005	\$ 1,318,281
Cross Winds (Phase I, II, III)	Tuscola County, MI	230.6	52.9	\$ 579,255	\$ 3,895,924
Crescent Wind	Jonesville, MI	166	24.4	\$ 267,180	\$ 1,796,986
Gratiot Farms Wind	Alma, MI	149.7	36.3	\$ 397,485	\$ 2,673,385
Heartland Farms Wind Park	Ithaca, MI	200	31.5	\$ 344,925	\$ 2,319,879
Solar Gardens- GVSU	Grand Rapids, MI	3	1.7	\$ 18,615	\$ 125,200
Solar Gardens- WMU	Kalamazoo, MI	1	0.6	\$ 6,570	\$ 44,188
Cadillac Solar Garden	Cadillac, MI	0.5	0.2	\$ 2,190	\$ 14,729
Circuit West	Grand Rapids, MI	0.5	0.2	\$ 2,190	\$ 14,729
ENERGY STORAGE					
Ludington Units 1-6	Ludington, MI	1138.0 (owned share)	1110	\$ 12,154,500	\$ 81,748,128
¹ ISAC = Intermediate seasonal accredited capacity ² SAC = Seasonal accredited capacity and is converted from ISAC based upon offered availability during RA and non-RA hours ³ 2024-2025 Summer PRA Settlement price of \$30/MW-day for Zone 7. ⁴ 2024-2025 PRA 75% CONE price of \$269.03/MW-day for Zone 7.					

Q. Please provide an overview of the generation asset strategy for Karn Units 3 and 4.

A. The strategic plan for Karn Units 3 and 4 is predicated on their planned retirement on May 31, 2031 as reflected in the Company's 2021 IRP Settlement Agreement. The overall remaining life objective for Karn Units 3 and 4 is to maintain capacity value from the customer's perspective. The capital expenditures and major maintenance expenses in the

1 plan are targeted to provide safe and regulatory compliant units, as well as maintain
2 capacity accreditation. Critical reliability investments required to keep the units available
3 will be included in the plan.

4 **Q. How will the Company's generation asset strategy for Karn Units 3 and 4 impact their**
5 **projected performance?**

6 A. It is anticipated that unit performance for Karn Units 3 and 4 will slightly degrade from
7 current performance. Based upon the Karn Units 3 and 4 capital and major maintenance
8 projects that I will discuss later in this direct testimony, the Company's generation asset
9 strategy is expected to result in an ROR of 18.00% at Karn Unit 3 and 18.00% at Karn
10 Unit 4 in the test year, as shown on Exhibit A-42 (RTB-2), lines 1 and 2, column (c).
11 During the five-year historical period from 2020 through 2024, Karn Unit 3 had an ROR
12 of 38.70% and Karn Unit 4 had an ROR of 24.76%, as shown on Exhibit A-42 (RTB-2),
13 lines 1 and 2, column (b).

14 **Q. How is this strategy reflected in the Projected Availability for Karn Units 3 and 4 in**
15 **the test year?**

16 A. The projected availabilities for Karn Units 3 and 4 in the test year are 69.13% and 72.97%,
17 respectively, as shown on Exhibit A-42 (RTB-2), lines 1 and 2, column (e). The
18 availability for Karn Unit 3 reflects a projected ROR of 18.00% and a PF of 15.69%, as
19 shown on Exhibit A-42 (RTB-2), line 1, columns (c) and (d). The planned outages for the
20 test year are scheduled to begin on October 12, 2026 and last for 30 days, and March 22,
21 2027 and last for 29 days, as reflected on Exhibit A-41 (RTB-1), lines 7 and 9. The
22 availability for Karn Unit 4 reflects a projected ROR of 18.00% and a PF of 11.01%, as
23 shown on Exhibit A-42 (RTB-2), line 2, columns (c) and (d). The planned outages for the

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test year are scheduled to begin on October 12, 2026 and last for 30 days, and March 22, 2027 and last for 29 days, as reflected on Exhibit A-41 (RTB-1), lines 8 and 10.

Q. How does the Projected Availability for Karn Units 3 and 4 translate into customer value?

A. As reflected on Exhibit A-42 (RTB-2), lines 1 and 2, column (f), during the five-year historical period from 2020 through 2024, Karn Unit 3 had a NEV of -\$8.1 million and Karn Unit 4 had a NEV of -\$10.4 million. The 2024 NEV for each of these units was -\$1.7 million and -\$0.4 million for Karn Units 3 and 4, respectively.

Q. Please explain why the NEVs for Karn Units 3 and 4 are negative.

A. The NEVs for Karn Units 3 and 4 are negative due to required operation in support of capacity demonstration testing, unit performance validation, and operator training. During this operation, the units are operated as Must-Run resources in the MISO Energy Market and as such, they are price takers. In order to minimize the impact of the required operation of the units, the Company performs those activities during periods in which operation is most economic. However, despite the fact that the NEVs are slightly negative, the units provide a significant amount of capacity value, which far outweighs the negative NEV values. In addition, the Company's ability to have these units dispatched during tight generation days provides reliability benefits for the Company's customers and the MISO energy market.

Q. Please quantify the capacity value for Karn Units 3 and 4.

A. As reflected in Table 2, the capacity value based upon the settlement price for Zone 7 in the 2024-2025 PRA is \$4.0 million for Karn Unit 3 and \$5.9 million for Karn Unit 4. The

hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2024-2025 PRA is \$27.0 million for Karn Unit 3 and \$39.9 million for Karn Unit 4.

Q. Please provide an overview of the generation asset strategy for the Zeeland Plant.

A. The strategic plan for the Zeeland Plant is predicated on plant operation through Planning Year 2040. The overall long-term objective for the Zeeland Plant is to increase economic dispatch and capacity from the customer's perspective. The units provide significant value to customers in both the energy and resource adequacy markets and the turbine projects discussed later in this direct testimony aim to increase customer value. The capital expenditures and major maintenance expenses in the plan are targeted to provide a safe, regulatory compliant, and reliable unit. Critical reliability investments required to keep the units available will be included in the plan. Projects that are targeted to improve dispatch and reliability, such as the turbine projects, are included in the plan as they provide value to customers.

Q. How will the Company's generation asset strategy for the Zeeland Plant impact its projected performance?

A. It is anticipated that site performance will remain relatively consistent with current performance. Based upon the Zeeland Plant capital and major maintenance projects that I will discuss later in this testimony, the Company's generation asset strategy is expected to result in an ROR of 4.0% at the Zeeland Plant in the test year, as shown on Exhibit A-42 (RTB-2), lines 10 through 12, column (c). During the five-year historical period from 2020 through 2024, the Zeeland Plant had ROR values at or below 7.48% for all units, as shown on Exhibit A-42 (RTB-2), lines 10 through 12, column (b).

1 **Q. How is this strategy reflected in the Projected Availability for the Zeeland Plant in**
2 **the test year?**

3 A. The Projected Availability for the combined cycle generating units (Units 1 and 2) at the
4 Zeeland Plant in the test year is 87.80%, as shown on Exhibit A-42 (RTB-2), line 10,
5 column (e). The Zeeland Combined Cycle (Units 3, 4, and 5) Generating Unit availability
6 is based upon a projected ROR of 4.0% and a PF of 8.54%, as shown on Exhibit A-42
7 (RTB-2), line 10, columns (c) and (d). The Projected Availabilities for each of the simple
8 cycle generating units at the Zeeland site in the projected test year are 89.98%, as shown
9 on Exhibit A-42 (RTB-2), lines 11 and 12, column (e). Each of the Zeeland simple cycle
10 generating unit Projected Availabilities are based upon projected RORs of 4.0% and PFs
11 of 6.27%, as shown on Exhibit A-42 (RTB-2), lines 11 and 12, columns (c) and (d). There
12 are no outages greater than 28 days scheduled for the Zeeland combined cycle units
13 (Units 3, 4, and 5) in the projected test year ending April 30, 2027, however there are
14 several shorter duration outages of 14 days, each scheduled in May and October, 2026.
15 There are no outages greater than 28 days scheduled for the Zeeland simple cycle units
16 (Units 1 and 2) in the projected test year ending April 30, 2027, however there is a 13-day
17 outage on each unit in the spring of 2026, a 3-day outage on each unit in September 2026,
18 and a 14-day outage on each unit in the spring of 2027. These outages are scheduled during
19 periods in which energy prices are projected to be lower, thereby reducing the impact of
20 the outages on customers. In addition, the outages are scheduled to maximize future
21 capacity attribution for the units given the MISO seasonal resource adequacy construct.

1 **Q. How does the Zeeland Plant Projected Availability translate into customer value?**

2 A. As reflected on Exhibit A-42 (RTB-2), lines 10 through 12, column (f), during the five-year
3 historical period from 2020 through 2024, the Zeeland Plant provided a total NEV of
4 \$220.5 million. The 2024 NEV for Zeeland was \$49.4 million.

5 **Q. Please quantify the capacity value for the Zeeland Plant.**

6 A. As reflected in Table 2, the Zeeland Plant capacity value based upon the settlement price
7 for Zone 7 in the 2024-2025 PRA is \$8.8 million and the Zeeland Plant hypothetical
8 capacity value based upon 75% of CONE for Zone 7 in the 2024-2025 PRA is
9 \$59.5 million.

10 **Q. Please provide an overview of the generation asset strategy for the Jackson Plant.**

11 A. The strategic plan for the Jackson Plant is predicated on plant operation through Planning
12 Year 2040. The overall long-term objective for the Jackson Plant is to maintain economic
13 dispatch and capacity from the customer's perspective. The units provide significant value
14 to customers in both the energy and resource adequacy markets. The capital expenditures
15 and major maintenance expenses in the plan are targeted to provide a safe, regulatory
16 compliant, and reliable unit. Critical reliability investments required to keep the units
17 available will be included in the plan. Projects that are targeted to improve reliability will
18 be included in the plan if they provide value to customers.

19 **Q. How will the Company's generation asset strategy for the Jackson Plant impact its**
20 **projected performance?**

21 A. It is anticipated that site performance will remain relatively consistent with current
22 performance. Based upon the Jackson Plant capital and major maintenance projects that
23 I will discuss later in this direct testimony, the Company's generation asset strategy is

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1 expected to result in an ROR of 4.50% at the Jackson Plant in the test year, as shown on
2 Exhibit A-42 (RTB-2), line 13, column (c). During the five-year historical period from
3 2020 through 2024, the Jackson Plant had an actual ROR of 8.22%, as shown on Exhibit
4 A-42 (RTB-2), line 13, column (b).

5 **Q. How is this strategy reflected in the Projected Availability for the Jackson Plant in**
6 **the test year?**

7 A. The Projected Availability for all of the generating units at the Jackson site in the test year
8 is 92.09%, as shown on Exhibit A-42 (RTB-2), line 13, column (e). The Projected
9 Availability for the Jackson site reflects a projected ROR of 4.50% and a PF of 3.57%, as
10 shown on Exhibit A-42 (RTB-2), line 13, columns (c) and (d). There are no major planned
11 outages in excess of 28 days for the Jackson units in the test year, however a short 12.5-day
12 outage is scheduled April 2027. In addition, several derates are scheduled to perform
13 inspections and maintenance on various generating units in September and October 2026
14 and March of 2027.

15 **Q. How does the Jackson Plant Projected Availability translate into customer value?**

16 A. As reflected on Exhibit A-42 (RTB-2), line 13, column (f), during the five-year historical
17 period from 2020 through 2024, the Jackson units provided a total NEV of \$158.4 million.
18 The 2024 NEV for the Jackson Plant was \$24.1 million.

19 **Q. Please quantify the capacity value for the Jackson Plant.**

20 A. As reflected in Table 2, the Jackson Plant capacity value based upon the settlement price
21 for Zone 7 in the 2024-2025 PRA is \$5.6 million and the Jackson Plant hypothetical
22 capacity value based upon 75% of CONE for Zone 7 in the 2024-2025 PRA is
23 \$37.5 million.

1 **Q. How will the Company's generation asset strategy for the Covert Plant impact its**
2 **projected performance?**

3 A. It is anticipated that site performance will remain relatively consistent with past
4 performance under different ownership. Based upon the Covert Plant capital and major
5 maintenance projects that I will discuss later in this direct testimony, the Company's
6 generation asset strategy is expected to result in an ROR of 7.00% for all three units at the
7 Covert Plant in the test year, as shown on Exhibit A-42 (RTB 2), lines 14 through 16,
8 column (c).

9 **Q. How is this strategy reflected in the Projected Availability for the Covert Plant in the**
10 **test year?**

11 A. The Projected Availability for each of the combined cycle generating units at the Covert
12 Plant in the test year ranges from 74.12% to 87.54%, as shown on Exhibit A-42 (RTB-2),
13 lines 14 through 16, column (e). The Covert Unit 1 unit availability of 74.12% is based
14 upon projected ROR of 7.00% and a PF of 20.30%, as shown on Exhibit A-42 (RTB-2),
15 line 14, columns (c) and (d); the Covert Unit 2 unit availability of 87.54% is based upon
16 projected ROR of 7.00% and a PF of 5.87%, as shown on Exhibit A-42 (RTB-2), line 15,
17 columns (c) and (d); and the Covert Unit 3 unit availability of 84.80% is based upon
18 projected ROR of 7.00% and a PF of 8.81%, as shown on Exhibit A-42 (RTB-2), line 16,
19 columns (c) and (d). The Company will conduct major inspections at all three of the Covert
20 Units during the bridge period/test year. The planned outage for the test year for Covert
21 Unit 1 is scheduled to begin on September 1, 2026 and last for 59 days as reflected on
22 Exhibit A-41 (RTB-1), line 2. The planned outage for the bridge period for Covert Unit 2
23 began on March 1, 2025 and ended on May 25, 2025. The planned outage for the bridge

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1 period/test year for Covert Unit 3 is scheduled to begin on March 15, 2026 and last for
2 59 days, as reflected on Exhibit A-41 (RTB-1), line 1. These outages are scheduled for
3 periods in which energy prices are projected to be lower, thereby reducing the impact of
4 the outages on customers. In addition, the outages are scheduled to maximize future
5 capacity attribution for the units given the MISO seasonal resource adequacy construct.

6 **Q. How does the Covert Plant Projected Availability translate into customer value?**

7 A. As reflected on Exhibit A-42 (RTB-2), lines 14 through 16, column (f), during the
8 19-month historical period beginning June 1, 2023 through December 31, 2024, the Covert
9 units provided a total NEV of \$49.4 million. The 2024 NEV for the Covert Plant was
10 \$24.1 million.

11 **Q. Please quantify the capacity value for the Covert Plant.**

12 A. As reflected in Table 2, the Covert Plant capacity value based upon the settlement price for
13 Zone 7 in the 2024-2025 PRA is \$10.4 million and the Covert Plant hypothetical capacity
14 value based upon 75% of CONE for Zone 7 in the 2024-2025 PRA is \$70.2 million.

15 **Q. Please provide an overview of the Company's generation asset strategy for the River**
16 **Hydro units.**

17 A. The strategic plan for the Company's River Hydro units is currently predicated on
18 operating the units consistent with the Company's Federal Energy Regulatory Commission
19 ("FERC") project licenses. Continued operation of these facilities is assumed in the
20 Company's current IRP that was approved by the MPSC in Case No. U-21090. These units
21 deliver customer value by providing renewable energy and capacity. River Hydro facilities
22 also provide value to their surrounding local communities and to the state of Michigan in
23 the form of recreational opportunities, natural preservation, and environmental benefits.

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1 The overall long-term objective for the River Hydro units is to maintain safe and reliable
2 River Hydro sites for our customers, to ensure compliance with FERC obligations and
3 other regulatory requirements, and to continue providing valuable benefits to local
4 residents, surrounding communities, and the state of Michigan.

5 **Q. Is it possible the River Hydro facilities could be retired early or not be relicensed?**

6 A. Yes. The Company is always evaluating its long-term generation strategy, including for
7 the River Hydro units. As a result of a Settlement Agreement in the Company's most
8 recent general electric depreciation case, Case No. U-20849 and a filing extension
9 approved in Case No. U-21783, Consumers Energy will present retirement and
10 decommissioning analysis for its River Hydro facilities to the Commission by the end of
11 2025. The Company will evaluate each facility and determine the best path forward from
12 the perspective of Consumers Energy, its customers, and the State of Michigan. Although
13 this analysis has not been completed, it is clear that compliance with FERC requirements
14 will require continued investment in safety and reliability upgrades to operate these River
15 Hydro facilities well into the future.

16 **Q. Has the Company presented any River Hydro capital investments in this electric rate**
17 **case?**

18 A. No. In the March 21, 2025 Final Order in the Company's 2024 Electric Rate Case No.
19 U-21585, the Commission found that the "company may use deferred regulatory
20 accounting of the revenue requirement on actual capitalized investments incurred subject
21 to review in the company's next electric rate case."² The Commission went on to state that
22 this accounting authority does not relieve the Company of meeting the evidentiary burden

² Case No. U-21585, March 21, 2025 Final Order, p 157.

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1 for its investments. As such, the Company has not presented any River Hydro projects for
2 the bridge period and test year and intends to seek recovery in a future regulatory
3 proceeding.

4 **Q. Has the Company presented actual River Hydro investments for the historical test**
5 **year?**

6 A. No. As discussed in more detail in the direct testimony of Company witness Myers, the
7 Company is requesting the continuation of the deferral through the test year of this rate
8 case and, as such, has not presented its actual 2024 River Hydro capital expenditures. This
9 is due to the continuing uncertain future of the River Hydros. The Company's
10 potential future scenarios for the River Hydros include divestiture, decommissioning, and
11 relicensing and continuing operation.

12 **Q. What is the status of the Request for Proposals ("RFP") for River Hydro divestiture?**

13 A. The Company launched an RFP to identify potential buyers for its 13 River Hydro facilities
14 on February 15, 2024. As part of the first phase of the RFP, which involved bidder
15 screening based on, among other things, qualifications and indicative pricing, the Company
16 received responses to the RFP on March 15, 2024. The Company evaluated the bids and
17 moved to the second phase of the RFP in April of 2024.

18 **Q. Please discuss Phase 2 of the RFP for River Hydro divestiture.**

19 A. Phase 2 involved initially engaging with seven selected entities in due diligence,
20 negotiations, and potential sale agreement(s). Due diligence was completed during the
21 summer of 2024, at which time negotiations began with selected bidders. The Company's
22 negotiations are continuing with the expectation of reaching a contract mid-year 2025.

1 **Q. What are the next steps following the execution of a contract for divestiture?**

2 A. To the extent that the Company can reach an agreement on their divestiture, the Company
3 would file an application with the MPSC and FERC for approval of the sale and related
4 agreements.

5 **Q. How will the Company move forward if divestiture fails or is rejected by the**
6 **Commission?**

7 A. To the extent that the Company is unable to reach an agreement for sale of the River Hydros
8 or a potential sale is rejected, the Company would revisit the decision to relicense or
9 decommission the River Hydros, with the intention of making a decision as soon as
10 possible following a decision to not divest.

11 **Q. Is the Company requesting the recovery of O&M expense for the River Hydros in this**
12 **proceeding?**

13 A. Yes. The Company has reflected River Hydro O&M expense in my Exhibit A-43 (RTB-4)
14 for the historic year, the 16-month bridge period, and the test year. The Company will
15 discuss its proposal for future O&M expense later in this direct testimony.

16 **Q. How will the Company's generation asset strategy for the River Hydro units impact**
17 **their projected performance?**

18 A. It is anticipated that future River Hydro unit performance will remain relatively consistent
19 with current River Hydro unit performance, provided that necessary investments are made
20 to ensure safe and reliable operation. In other words, as assumed in Consumers Energy's
21 current IRP, the Company currently expects its River Hydro facilities can continue to
22 deliver reliable clean energy to customers while maintaining their long record of
23 operational, safety, and environmental performance. Based upon the River Hydro unit

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major maintenance projects that I will discuss later in this direct testimony, the Company's generation asset strategy is expected to result in an ROR of 5.60% for the River Hydro units in the projected test year ending April 30, 2027, as shown on Exhibit A-42 (RTB-2), line 9, column (c). During the five-year historical period from 2020 through 2024, the River Hydro units had an ROR of 9.48% for all units, as shown on Exhibit A-42 (RTB-2), line 9, column (b).

Q. How is this strategy reflected in the projected availability for the River Hydro units in the projected test year?

A. The projected availability for all of the River Hydro units in the projected test year is 89.38%, as shown on Exhibit A-42 (RTB-2), line 9, column (e). The Projected Availability for the River Hydro units reflects a projected ROR of 5.60% and a PF of 5.32%, as shown on Exhibit A-42 (RTB-2), line 9, columns (c) and (d). These projections reflect (i) a 109-day planned outage at Cooke Unit 1 for replacement of the downstream right retaining wall, (ii) a 270-day planned outage at Five Channels Unit 2 for wicket gate replacement, (iii) a 270-day planned outage at Croton Unit 3 for unit overhaul, (iv) a 249-day planned outage at Webber Unit 1 for generator rewind and unit overhaul, (v) a 270-day planned outage at Loud Unit 1 for wicket gate replacement, (vi) a 82-day planned outage at Tippy Units 1-3 for an electric safety upgrade, and (vii) a 270-day planned outage at Croton Unit 4 for periodic inspection and thrust bearing inspection.

Q. How does the River Hydro unit Projected Availability translate into customer value?

A. As reflected on Exhibit A-42 (RTB-2), line 9, column (f), during the five-year historical period from 2020 through 2024, the River Hydro units which are registered with MISO

(Alcona, Croton, Hardy, Hodenpyl, and Tippy) provided a total NEV of \$44.9 million. The 2024 NEV for the River Hydro units registered with MISO was \$6.6 million.

Q. Please quantify the capacity value for the River Hydro units?

A. As reflected in Table 2, the capacity value of the River Hydro units based upon the settlement price for MISO Zone 7 in the 2024-2025 MISO PRA is \$0.8 million and the River Hydro unit hypothetical capacity value based upon 75% of Cost of New Entry for Zone 7 in the 2024-2025 PRA is \$5.4 million.

Q. Please provide an overview of the generation asset strategy for Ludington.

A. The strategic plan for Ludington is predicated on retiring the units by July 30, 2069. The Ludington units recently underwent a major overhaul that was intended to provide increased capacity and generation, increased efficiency, reduced maintenance, and an extended service life which supported the 50-year FERC license extension granted in 2019. Ludington is a FERC-regulated hydroelectric facility for which dam safety investments are identified and initiated as a result of regulatory compliance and adherence to FERC processes, including the FERC Part 12 process.

Q. How will the Company's generation asset strategy for Ludington impact its projected performance?

A. Based upon the Ludington capital and major maintenance projects that I will discuss later in this direct testimony, the Company's generation asset strategy is expected to result in an ROR of 3.50% for the Ludington units in the test year, as shown on Exhibit A-42 (RTB-2), lines 3 through 8, column (c). During the five-year historical period from 2020 through 2024, the Ludington units had average ROR values ranging from 4.94% to 7.75%, as shown on Exhibit A-42 (RTB-2), lines 3 through 8, column (b).

1 **Q. How do the Ludington Units factor into the Company's future renewable energy**
2 **strategy as outlined in the IRP?**

3 A. Given the intermittent nature of solar and wind generation and the Company's plans to
4 move to a zero net carbon future, Ludington is becoming a more critical component of the
5 Company's generation portfolio since it can deliver a significant amount of energy in a
6 short time period; providing energy supply from the reservoir during periods when the
7 wind doesn't blow and/or the sun doesn't shine. Additionally, when there is an
8 over-abundance of wind and/or solar generation, Ludington can utilize the excess energy
9 to fill the reservoir. Ludington's large energy storage capability greatly enables the
10 transition to renewable energy. However, defective and non-conforming work performed
11 by Toshiba during recent overhaul efforts must be resolved to ensure Ludington can fully
12 provide these intended benefits over its remaining life.

13 **Q. How is this strategy reflected in the Projected Availability for Ludington in the test**
14 **year?**

15 A. The Projected Availabilities for all of the Ludington units in the projected test year ranges
16 from 0.00% to 84.01%, as shown on Exhibit A-42 (RTB-2), lines 3 through 8, column (e).
17 The Projected Availabilities for the Ludington generating units reflect a projected ROR of
18 3.50% and PFs ranging from 12.94% to 100.00%, as shown on Exhibit A-42 (RTB-2),
19 lines 3 through 8, columns (c) and (d). There are four major outages planned for the
20 Ludington units in the test year: a 274-day outage on Ludington Unit 3 beginning on
21 September 2, 2026 as presented on Exhibit A-41 (RTB-1), line 3; a 49-day outage on
22 Ludington Unit 6 beginning on September 8, 2026 as presented on Exhibit A-41 (RTB-1),
23 line 4; a 42-day outage on Ludington Unit 5 beginning on September 10, 2026 as presented

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1 on Exhibit A-41 (RTB-1), line 5; and a 683-day outage on Ludington Unit 4 beginning on
2 October 19, 2026 as presented on Exhibit A-41 (RTB-1), line 6. In addition, shorter
3 outages on all six Ludington units are scheduled throughout the test year, primarily in the
4 spring and fall. These outages will be used, in part, to perform cooling water strainer
5 cleaning, install and remove the barrier net, and perform other necessary inspections. To
6 the extent possible, the outages are scheduled during periods in which the likelihood of
7 Ludington unit dispatch is lower, thereby reducing the impact of the outages on customers.

8 **Q. Please provide an overview of the generation asset strategy for the Renewable Energy**
9 **Assets.**

10 A. The Company's strategic plan for Renewable Energy Assets, both wind and solar,
11 continues to be primarily driven by the Company's MPSC-approved 2021 IRP Settlement
12 Agreement. Consistent with the IRP, all previously identified wind assets were in service
13 throughout 2024. For solar, the Company plans to continue to add incremental solar
14 resources in accordance with its Clean Energy Plan and Renewable Energy Plans. These
15 solar resources are being added pursuant to the Company's annual IRP solicitations, as
16 discussed in more detail later in this direct testimony. In addition, the Company anticipates
17 that it will also add wind and solar assets for the foreseeable future in support of the
18 Company's Voluntary Green Pricing Program, and their costs will be reconciled through
19 the Company's Renewable Energy Plan.

20 **Q. Is the Company requesting recovery of renewable energy assets in this proceeding?**

21 A. No. The Commission approved the movement of cost recovery for renewable energy
22 resources to the Company's Renewable Energy Plan in its March 21, 2025 Order in Case

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No. U-21585. As such, all costs for renewable energy assets will be presented and reconciled in renewable energy plans.

Q. How will the enactment of PA 235 of 2023 impact the Company's future renewable energy portfolio?

A. As previously discussed in this direct testimony, the Company filed a Renewable Energy Plan Amendment on November 15, 2024. PA 235 of 2023 has established both renewable and clean energy targets for the future beginning with a renewable energy compliance target of 50% in 2030. The newly passed law became effective on February 27, 2024 and provides for the utilization of renewable energy assets from anywhere within the MISO footprint.

The Company's Renewable Energy Plan Amendment proposes the addition of 2,800 MW of renewable energy wind resources and an additional 1,000 MW of renewable energy solar resources, over and above the Company's glidepath established in its 2021 IRP settlement.

Q. How do the Company's renewable assets translate into customer value?

A. Similar to the Company's River Hydro units, the production cost of the Company's renewable energy assets is zero. As such, all energy sold into the MISO energy market has value provided that the MISO locational marginal prices are positive. Additionally, renewable assets provide the Company's customers with renewable energy credits. As reflected on Exhibit A-42 (RTB-2), lines 17 through 18, column (f), during the five-year historical period from 2020 through 2024, the Cross Winds Energy Park and the Lake Winds Energy Park provided a total NEV of \$166.7 million. As reflected on Exhibit A-42 (RTB-2), lines 19 through 20, column (f), during the three-year historical period from 2022

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1 through 2024, Gratiot Farms Wind and Crescent Wind provided total NEV of
2 \$68.5 million. Heartland Farms Wind Park began commercial operation on December 29,
3 2023, and as reflected on Exhibit A-42 (RTB-2), line 21, column (f), generated \$0.4 million
4 in NEV in 2023. The Company began to measure the NEV for its solar assets in 2020 and
5 the 2020 through 2024 NEV for its Solar Garden Assets totaled \$1.1 million.

6 **Q. Please quantify the capacity value for renewable energy assets.**

7 A. As reflected in Table 2, the renewable asset capacity value based upon the settlement price
8 for Zone 7 in the 2024-2025 PRA is \$0.4 million and the renewable asset hypothetical
9 capacity value based upon 75% of CONE for Zone 7 in the 2024-2025 PRA is \$2.5 million.

10 **Q. Why have you included a hypothetical capacity value for each of the generating units**
11 **or category of generating units?**

12 A. I have included these hypothetical values to reflect the capacity values that the Company
13 uses in its capacity planning process. Company witness Metz provides additional
14 information regarding the capacity value of the Company's generation assets in MISO's
15 PRA as well as the projected capacity margin in future years for Zone 7.

16 **Q. How will the Company determine the reasonableness and prudence of additional**
17 **investments in the electric generating fleet?**

18 A. Additional investment in the remaining units over and above those necessary to maintain
19 safety and regulatory compliance would require some level of economic benefit for
20 customers, otherwise the investment does not make sense. The generating unit periodic
21 outage plans, projected RORs and, ultimately, projected availability for each generating
22 unit or category of generating units reflects the Company's generation asset strategy.

SECTION II

ENVIRONMENTAL REGULATIONS

OVERVIEW

Q. Can you please list the environmental regulations with which Consumers Energy is required to comply and that are relevant to expenditures for which the Company is seeking recovery in this case?

A. Yes. The Company's fossil-fueled Electric Generating Units ("EGUs") are subject to numerous complex and overlapping air, water, and waste regulations.

CURRENT (ON-GOING) ENVIRONMENTAL COMPLIANCE

Environmental Regulations – Air Quality

Q. Describe Consumers Energy's Existing Air Quality Compliance Strategy ("AQCS").

A. Over the past decade, Consumers Energy has had expenditures to comply with a variety of air quality-related regulations, including the Cross State Air Pollution Rule, the Mercury and Air Toxics Standards, and the Michigan Mercury Rule, among others. The background and purpose of each such rule has been discussed in the testimony of prior rate cases, including Case No. U-17735. To comply with these regulations, Consumers Energy created the AQCS. Cost recovery reflecting the Company's AQCS was approved in the November 19, 2015 Order in the Company's 2014 Electric Rate Case (Case No. U-17735). This AQCS has prudently ensured compliance with applicable state and federal air-quality related regulations. The Company's actions and investments to achieve such compliance have been performed in a manner which has minimized, to the extent reasonably possible, the associated costs for customers. The investments made to ensure environmental compliance have allowed the continued operation of coal generation while the Company transitions to carbon-free generation sources like solar.

1 **Q. Are there any updates to the air quality-related regulations for which the Company's**
2 **existing AQCS complies?**

3 A. Yes. In April 2022 the Environmental Protection Agency ("EPA") proposed the "Federal
4 Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National
5 Ambient Air Quality Standard" under the "good neighbor" provision of the Clean Air
6 Act. The EPA's rule was finalized, effective March 15, 2023 but this revision was stayed
7 in 2024 and the prior 2017 Cross-State Air Pollution Rule ("CSAPR") remains in effect.
8 On March 12, 2025, U.S. EPA Administrator Lee Zeldin announced the agency will
9 undertake action to "end the Good Neighbor Plan." It is most likely that CSAPR will remain
10 in effect. The Company will continue to monitor the rule and evaluate various options for
11 compliance as needed.

12 **Q. What are the capital investments and/or O&M expenses the Company is seeking to**
13 **recover in this case that are specifically related to air quality control?**

14 A. Any O&M required for the operation of the air quality control systems that the Company
15 is seeking recovery can be found in Exhibit A-43 (RTB-4).

16 **Q. Are you seeking recovery of any expenses related to the regulation of greenhouse**
17 **gases from EGUs?**

18 A. No, not at this time. On June 19, 2019, the EPA finalized three rulemakings: (i) repeal of
19 the Clean Power Plan; (ii) issuance of the final Affordable Clean Energy ("ACE") Rule
20 and; (iii) issuance of new Clean Air Act ("CAA") section 111(d) regulations. In May 2024,
21 EPA issued a Final GHG standards for new and existing fossil fuel-fired EGUs under
22 Section 111 of the CAA and the ACE Rule was repealed. These new requirements do not
23 impact the Company's fleet due to the planned retirement date for our last coal units.

Existing gas-fired combustion turbine units are not subject to this rule and therefore those Company units are also not subject to this rule. On March 12, 2025, EPA Administrator Lee Zeldin announced the agency will undertake actions "reconsidering regulations on power plants (Clean Power Plan 2.0)" which could imply that these regulations will be revised at some point in the future.

Environmental Regulations and Compliance Strategy – Waste

Q. Can you please describe the relevant parts of the Resource Conservation and Recovery Act ("RCRA") as related to Coal Combustion Residuals ("CCR") management?

A. On April 17, 2015, the EPA published 40 CFR Parts 257 and 261, Disposal of CCRs from Electric Utilities, in the Federal Register under Subtitle D of the RCRA. The rules establish minimum national criteria for purposes of determining which CCR solid waste disposal facilities and solid waste management practices pose a reasonable probability of adverse effect on health or the environment under RCRA. The rule is considered self-implementing, meaning that affected facilities must certify compliance with the published standards and schedules. By codifying standards under Subtitle D, Owners and Operators are not required to obtain permits, and states are not required to adopt and implement the new rules. Instead, the rules' only enforcement mechanism is for a state or citizen group to bring a RCRA citizen suit in federal district court against any facility that is alleged to be in noncompliance with the newly promulgated minimum standards. In December 2016, the Water Infrastructure Improvements for the Nation ("WIIN") Act was passed and signed into law. Section 2031 of the legislation provides authority for state implementation of coal ash management through a state permit program in lieu of the

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1 current enforcement of the CCR Rule through the RCRA citizen-suit authority. States may
2 elect to submit a CCR permit program to the EPA for approval. The State of Michigan
3 revised its solid waste statute in late 2018 to outline a state CCR permitting program.
4 Michigan has submitted its application to the EPA for a permit program and is awaiting
5 the EPAs review of administrative completeness. In the interim, the EPA has information
6 gathering and enforcement authorities to enforce the CCR Rule as provided in the WIIN
7 Act.

8 The existence of a state permitting program allows Department of Environment,
9 Great Lakes, and Energy (“EGLE”) to issue permits under Michigan’s solid waste
10 management statute (Part 115 of the Natural Resources and Environmental Protection Act
11 of 1994 (“NREPA”), as amended) to regulate compliance schedules and activities for CCR
12 landfills and surface impoundments. Although the current state CCR permitting program
13 was passed into law and Consumers Energy is obligated to comply with the associated
14 statute, permits, and licenses, the program must be approved by the EPA on the basis that
15 it is “as protective as” the CCR Rule to avoid dual state and federal regulation. Thus,
16 similar compliance standards are required within the state permitting program, including
17 requirements to make compliance documentation publicly available, completing the work,
18 and then self-reporting by providing notifications to EGLE and posting to a publicly
19 accessible compliance website.

1 **Q. What are the capital and/or O&M investments Consumers Energy is seeking to**
2 **recover in this case that are specifically related to RCRA compliance and/or overall**
3 **CCR Management?**

4 A. The Company's CCR management compliance strategy was approved in Case No.
5 U-18322. The major capital work for compliance has been completed. The Cost of
6 Removal ("COR") and/or O&M required for the management of CCRs under the RCRA
7 that the Company is seeking to recover can be found in Exhibits A-139 (JJK-3) and A-43
8 (RTB-4). The COR expenses represent historical expenses only. Separately, there are
9 closure activities that will continue throughout the bridge period and test year and beyond;
10 however, those expenses are COR and are not included in this filing.

11 **Environmental Regulations and Compliance Strategy – Water**

12 **Q. Can you please describe the relevant parts of the Steam Electric Effluent Guidelines**
13 **("SEEG") as related to wastewater management?**

14 A. On April 24, 2024, EPA finalized a supplemental rulemaking to strengthen discharge limits
15 for Flue Gas Desulfurization ("FGD") wastewater, bottom ash transport water, Combustion
16 Residual Leachate ("CRL"), and legacy wastewaters. FGD and legacy wastewaters are not
17 and will not be generated at Consumers Energy locations. Campbell will be retiring in 2025
18 and will comply with the cessation of coal combustion by 2028 subcategory for bottom ash
19 transport water. CRL discharge limits will impact the Campbell dry ash landfill where the
20 Company is completing a capital project to install a deep injection well to address this
21 issue. Paired with the 2024 RCRA rule, there is risk at the J.C. Weadock ("Weadock"),
22 Karn, B.C. Cobb ("Cobb"), and J.R. Whiting ("Whiting") sites. The 2024 RCRA rule does
23 not allow free liquid in closed ash landfills, but it also does not define what free liquid is.

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1 If the 2024 RCRA rule were to require installation of dewatering wells in closed landfills,
2 any wastewater generated would likely be classified as unmanaged CRL subject to arsenic
3 and mercury limits and require treatment prior to surface water discharge.

4 **Q. What are the capital and/or O&M investments Consumers Energy is seeking to**
5 **recover in this case that are specifically related to RCRA compliance and/or overall**
6 **wastewater management?**

7 A. The Company is seeking to recover costs for the installation of a deep well to be used for
8 wastewater disposal at the Campbell facility. The Campbell facility will cease generation
9 in June 2025 and on-site operations will cease by the end of 2025. Due to wastewater
10 generated during decommissioning, the sitewide National Pollutant Discharge Elimination
11 System (“NPDES”) permit will remain open through demolition. Campbell has an active
12 landfill with leachate which requires treatment/disposal. After on-site operations end, the
13 flow characteristics of the Campbell facility will change and there will be a need to manage
14 leachate differently as the current outfall location will no longer be available for use. SEEG
15 rules require zero liquid discharge of CRL no later than December 31, 2029; however,
16 because of the change in flow characteristics by the end of 2025, the Company considered
17 several options to address the ongoing leachate water, including transport for offsite
18 disposal, offsite treatment, onsite treatment and onsite disposal. Ultimately, onsite disposal
19 via a deep-injection well was selected and is currently being permitted by EGLE and
20 EPA. The Company also submitted a NPDES permit application revision on November 7,
21 2024. Please refer to page 8, line 27, and page 9, line 22 of Exhibit A-12 (RTB-3),
22 Schedule B-5.2 for projected capital expenditures in the bridge period and test year.

SECTION III

GENERATION CAPITAL EXPENDITURES

OVERVIEW

Q. What factors does the Company consider in determining the capital investments that it will make at its generating plants?

A. The major drivers in the determination of generation capital investments are plant safety, compliance with regulations, and reliability. Consumers Energy's strategy for complying with environmental regulations was previously discussed in this direct testimony.

Q. Please describe Exhibit A-12 (RTB-3), Schedule B-5.2, Generation Capital Expenditures.

A. This exhibit presents the capital expenditures for Generation for the historical year 2024 through the projected test year - 12 months ending April 30, 2027. Exhibit A-12 (RTB-3), Schedule B-5.2, is a nine-page exhibit. Page 1 of this exhibit presents a summary of Generation capital expenditures for the Historical Period ended December 31, 2024, the Projected 16-month Bridge Period beginning January 1, 2025 and ending April 30, 2026, and the projected test year beginning May 1, 2026 and ending April 30, 2027. This summary information is broken down by Steam Power Generation, Hydraulic Power Generation, Pumped Storage Generation, and Other Production Plant. Pages 2 through 5 of this exhibit capture the same Historical Year, Bridge Period, and Test Year Generation capital expenditures information, but are presented by generating sites and environmental categories. This information is further detailed by Contractor, Labor, Materials, Business Expenses, Contingency, and Other. Page 6 of this exhibit represents a summary of pages 2 through 5 of this exhibit. Finally, pages 7 through 9 of this exhibit identify the capital projects and associated expenditures that are greater than \$1 million that contribute to the

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1 overall capital expenditures summarized on pages 1 through 6 of this exhibit. Specifically,
2 page 7 of this exhibit presents capital projects for the Historical Period ended December 31,
3 2024; page 8 of this exhibit presents capital projects for the Projected 16-month Bridge
4 Period beginning January 1, 2025 and ending April 30, 2026; and page 9 of this exhibit
5 presents capital projects for the projected test year ending April 30, 2027.

6 **Q. What project information is presented on Exhibit A-12 (RTB-3), Schedule B-5.2,**
7 **pages 7 through 9?**

8 A. Exhibit A-12 (RTB-3), Schedule B-5.2, pages 7 through 9, presents the generation type,
9 the generation unit, project type, project classification, project description, and project cost
10 information. The project type identifies whether the project is routine or non-routine.
11 Routine projects include work that is performed regularly; whereas non-routine projects
12 are typically undertaken once every 10 years or longer. The budget approval reflects the
13 status of internal approval for the project, including projected cost amount. Exhibit A-12
14 (RTB-3), Schedule B-5.2, page 7, includes both projected and actual capital project cost;
15 whereas, Exhibit A-12 (RTB-3), Schedule B-5.2, pages 8 and 9, includes only the project
16 projected amount.

17 **Q. What level of capital spending for generating plants does the Company request the**
18 **Commission to incorporate into rates in this case?**

19 A. The Company's rate relief request in this case reflects capital spending on projects for its
20 generating plants of \$145.252 million for the historical test year ended December 31, 2024
21 as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 1, line 17, column (b);
22 \$275.408 million in the projected 16-month Bridge Period ending April 30, 2026 as
23 shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 1, line 17, column (e); and

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1 \$188.638 million in the projected test year ending April 30, 2027 as shown on Exhibit A-12
2 (RTB-3), Schedule B-5.2, page 1, line 17, column (f).

3 **Q. Has the Company included any contingency in the requested capital expenditures for**
4 **Generation?**

5 A. No. The Company no longer includes contingency in its generation projects.

6 **Q. Please explain how the Company prioritizes its capital investments within**
7 **Generation.**

8 A. In evaluating capital investments, the Company's first priority is addressing safety,
9 regulatory, compliance, and continued operation related projects. These projects are
10 considered a mandatory cost of doing business. Safety, regulatory, compliance, and
11 continued operation-related projects provide economic value to customers in that they
12 allow the units to remain in service and avoid potential derates and/or shutdown due to an
13 intervention by various regulators including Occupational Safety and Health
14 Administration ("OSHA"), EGLE, the EPA, and FERC. In order to minimize the impact
15 of these projects on customers, the Company utilizes a least cost/best fit ("LCBF") analysis
16 for the investments necessary to satisfy service quality, safety, and federal and state policy
17 requirements.

18 **Q. How does the Company determine whether other projects get approved for funding?**

19 A. In accordance with the Company's generation asset strategy for each generating unit or
20 category of generating units, economic projects that are expected to reduce ROR,
21 maintenance cost or heat rate, all else being equal, are evaluated to ensure that their
22 implementation results in a net benefit to the customer. For a project to receive approval
23 for implementation, the projected benefits of the work must have a greater value than the

1 cost of implementing the project. In other words, the implementation of the project should,
2 at a minimum, result in a marginal customer benefit.

3 **Q. How does the Company evaluate other capital investments, such as economic**
4 **projects?**

5 A. The Company uses two financial measures, Internal Rate of Return (“IRR”) and Present
6 Value Ratio (“PVR”), as a means to evaluate and prioritize projected economic projects
7 within Generation. A complex financial model was developed in-house that allows the
8 Company to calculate and measure the numerous changes that result when improvements
9 (both O&M and Capital) are made to its rate-based generating units.

10 **Q. Does the Company calculate IRRs or PVRs for all projects?**

11 A. No. The Company calculates IRRs or PVRs for economic projects that are not considered
12 required but would yield net benefits to customers. Projects required for regulatory,
13 compliance, and/or continued operations are reviewed to assure that the project is cost
14 effective and results from a reasonable evaluation of alternatives, but because the project
15 must be done for compliance and continued operation, IRR or PVR may not be calculated.
16 When evaluating project alternatives related to regulatory, compliance, and/or continued
17 operations, IRRs or PVRs may be used to rank alternatives.

18 **Q. Please explain what you mean by projects for continued operations.**

19 A. Projects for continued operations refers to projects which are necessary to allow the
20 generating unit to continue to operate through its retirement date. Alternatives for projects
21 necessary for continued operation will generally be evaluated based upon LCBF. For this
22 evaluation, one of the alternatives will include a decision to not perform the project and
23 either retire the unit earlier than projected or operate the unit at a permanent derate.

1 **Q. How does the Company evaluate customer benefits associated with**
2 **generation-related capital investments?**

3 A. The Company uses replacement power cost estimates and PSCR impacts when evaluating
4 customer benefits. The Company also evaluates ROR and heat rate improvements, which
5 result in increased generation and/or lower cost generation.

6 **Q. How does the Company evaluate historical events which have impacted availability?**

7 A. The cause of each of the historical events impacting availability are evaluated and
8 measured, and the actions necessary to avoid the same or similar events are considered for
9 implementation. In many cases, actions necessary to prevent the event from recurring are
10 cost beneficial. The availability projections, including ROR, simply reflect the Company's
11 best estimate of the operational benefits of those corrective actions that have already been
12 taken or are planned to be taken, through the projected test year ending April 30, 2027.

13 **Q. Does the Company evaluate customer benefits associated with Outage Schedules?**

14 A. Yes, the Company uses historical market prices to evaluate timing around outages in an
15 effort to ensure the unit is available during periods in which market pricing is projected to
16 be high.

17 **Q. Is it possible that the Company could experience changes to its scheduled outages and**
18 **forecasted capital expenditures in the future?**

19 A. Yes. The Company often forecasts future actions and capital expenditures based on
20 currently available information, many months before the work is completed. To provide
21 some perspective, the outage schedule used in this case was approved in August 2023.
22 A review of the outage schedule used in this case identifies ten scheduled outages that
23 begin in May 2026 (20 months after the schedule was approved) and run through April 30,

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1 2027, 31 months later. During each of these ten scheduled outages, Consumers Energy has
2 scheduled a number of tasks to be performed. Because of the long lead times, the number
3 of outages scheduled during the test year, and the fact that several different tasks will be
4 performed during each outage, it is inevitable that some scheduled outages and forecast
5 capital expenditures will change. However, the Company has a history of prudent capital
6 investments in its generating facilities, which have been consistently supported by the
7 Commission.

8 **Q. Are there other reasons why outage schedule changes occur?**

9 A. Yes. Some of the reasons why outage schedule changes occur are: contractor availability,
10 parts availability, changes in regulations, design changes, outage scope changes, changes
11 in unit condition, and spot market prices. It is critical to point out that disallowance of
12 projected capital expenditures in electric rate cases leads to the cancellation of work scope
13 and outage plans, thus pushing needed investment to the future, continuing risk with plant
14 operations, and increasing customer cost due to lower availability.

15 **Q. Can you provide an example of when circumstances changed?**

16 A. Yes. The Company's fall 2023 outages for Karn Units 3 and 4 were originally scheduled
17 from October 1, 2023 through November 18, 2023. The Karn Unit 3 and 4 outages were
18 not performed due to availability of materials for the major work that was planned. Due to
19 the uncertainty of the retirement of Karn Units 3 and 4 as proposed in the Company's 2021
20 IRP, the preparation for these outages was not complete, including material delivery. As
21 such the planned work was deferred to 2024.

1 **Q. Please describe how the Company determines its generation projected capital**
2 **expenditure amounts.**

3 A. Consistent with the Company's generation asset strategy, generation projected capital
4 investments support the continued safe, regulatory compliant and reliable operations of the
5 Company's electric generating fleet. Projected capital investments are informed by
6 historical and anticipated performance of the units. The reasonableness of the generation
7 capital investments is indicated by the sustained or improved performance of the
8 Company's electric generating fleet relative to: (1) the safety of the employees, contractors,
9 and community at and around the generating facilities; (2) compliance with rules and
10 regulations; and (3) reliably participating in the energy, resource adequacy, and ancillary
11 services markets.

12 **Q. How are projects identified that are discussed later in this direct testimony?**

13 A. Generation System Planners assess the equipment performance and compare that
14 assessment with the generation asset strategy for the generating unit. Upon identification
15 of a potential project, the Planner will complete a project initiation document ("PID"). This
16 document defines the issue, alternatives considered for resolution, intended benefits or
17 consequences avoided, and suggested timing and a cost estimate. The document is
18 reviewed by multiple groups for alignment and ultimately routed for approval for inclusion
19 in the Long-Term Financial Plan ("LTFP"). PIDs entered into the LTFP will typically be
20 scheduled three to five years in the future to align with outages and provide the project
21 execution teams ample time to plan and engineer.

1 **Q. How were the projected capital expenditure amounts developed for each of the**
2 **projects discussed later in this direct testimony?**

3 A. Each project begins with the creation of a PID. The Planner will provide an initial cost
4 estimate for the project within the PID. The Planner utilizes past experience, contractor
5 cost estimates, internal estimates, Original Equipment Manufacturer (“OEM”) data, and
6 studies to provide the best estimate of the costs. This activity typically takes place three to
7 five years prior to the start of project execution.

8 **Q. How are PIDs related to Concept Approval Documents (“CADs”)?**

9 A. The PID is the mechanism utilized to allow projects to be considered for the LTFP. Once
10 the project is included in the LTFP and the project is within a year of start of execution,
11 the CAD is created. The CAD is templated from the PID and updated as necessary. The
12 CAD is then routed for approval to the designated level of management based on project
13 amount and, once approved, the project will be initiated.

14 **Q. Do adjustments to the projected capital investment amounts for each of the projects**
15 **occur prior to project implementation?**

16 A. Yes. As the project team progresses through the life cycle of a project, there are multiple
17 opportunities to better define project costs. Activities such as detailed engineering,
18 bidding, contractor involvement, and construction all allow for budgets to be better defined.
19 As this definition evolves, the projected capital investments are updated accordingly.

20 **Q. How does the Company account for uncertainties in its cost projections?**

21 A. When forecasting and budgeting for the Company’s generation projects, the Company
22 accounts for the uncertainty of less mature estimates by including contingency in its cost
23 estimates. For purposes of this rate case filing, the Company has already removed the

contingency component of its generation project cost estimates before filing the case since it has been disallowed in the past. The Company also utilizes industry standard cost estimating practices that involve class estimates having a prescribed range of potential cost outcomes based on estimate accuracy. The Commission has historically disallowed costs above the lower range for certain projects and cost estimate classes.

Q. What impact does this have on the Company's ability to fund needed generation capital projects?

A. If the Commission disallows both the contingency amount included in the project forecasts and an amount consistent with the bottom end of the range of estimate accuracy, it is virtually certain to underfund the Company's generation capital projects.

2024 HISTORICAL TEST YEAR CAPITAL EXPENDITURES

Q. How does the 2024 actual capital expenditure amount of \$145.252 million compare to the amount of capital expenditures reflected in the Company's request in Case No. U-21585?

A. In Case No. U 21585, the Company requested \$339.304 million for the 12 months ended December 31, 2024. The 2024 actual capital expenditure amount of \$145.252 million is \$194.052 million less than the projected amount.

Q. What is the basis for the gap in projected versus actual spending?

A. The reduction in the Company's actual capital expenditure amount is primarily attributable to the removal of the capital expenditures for IRP solar projects (Muskegon, Spring Creek, Mustang Mile, and Washtenaw) and the reduction in investment in the BESS projects. The Company withdrew the requested recovery of the IRP solar generation projects from Case No. U-21585 and has instead sought to recover them in its amended renewable energy plan

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1 Case No. U-21816. The removal of the investment for these projects for the 12-month
2 period ending December 31, 2025 reduced the projected capital expenditures by
3 \$130.597 million.

4 In addition, the Company identified delays in the commercial operation dates
5 (“CODs”) for the BESS projects. The projected investment amount for the 12 months
6 ended December 31, 2024 was \$39.672 million and the actual capital expenditure amount
7 was \$22.942 million, a difference of \$16.730 million. The CODs for the Weadock and
8 Iosco projects were pushed out beyond the test year in Case No. U-21585 so there was no
9 impact to the revenue requirement in the final order.

10 Also, as previously discussed in this direct testimony, the actual 2024 capital
11 expenditures do not include any River Hydro investment. The total investment on the River
12 Hydros for the 12 months ending December 31, 2024 was projected to be \$38.052 million
13 and the actual investment was only \$33.933 million. Several parties to the Company’s
14 2024 electric rate case recommended complete disallowance of the entire River Hydro
15 investment and, as such, the Company managed its investment in 2024.

16 Finally, the actual capital expenditures for Ludington for the 12-month period
17 ended December 31, 2024 came in at \$3.857 million versus the projected amount of
18 \$8.717 million. The total investment amount for Ludington was over \$20 million, however
19 a portion of the investment was recorded as a regulatory asset.³

³ See the February 28, 2025 report in Case No. U-21310.

1 **Q. How does the compilation of capital projects on Exhibit A-12 (RTB-3), Schedule**
2 **B-5.2, page 7, compare with the 14-month bridge capital projects reflected on Case**
3 **No. U-21585, Exhibit A-12 (RTB-3), Schedule B-5.2, page 8?**

4 A. A comparison of the projects on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7, with the
5 bridge period projects reflected on Case No. U-21585, Exhibit A-12 (RTB-3), Schedule
6 B-5.2, page 8, reveals that there are eleven projects on Exhibit A-12 (RTB-3), Schedule
7 B-5.2, page 7, which were not reflected on Case No. U-21585, Exhibit A-12 (RTB-3),
8 Schedule B-5.2, page 8. In addition, there were fourteen projects for the 14-month bridge
9 period that were reflected on Case No. U-21585, Exhibit A-12 (RTB-3), Schedule B-5.2,
10 page 8, that are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7. The River
11 Hydro projects were not considered in this evaluation due to their removal.

12 **Q. Please discuss the 14-month bridge period capital projects that were included on Case**
13 **No. U-21585, Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, that are not presented on**
14 **Exhibit A-12 (RTB-3), Schedule B-5.2, page 7.**

15 A. The following projects are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7,
16 due to the fact that their actual 2024 capital expenditure amount was less than \$1 million,
17 the project was disallowed, reduced in cost or removed, or not pursued in 2024. As
18 previously discussed, the entire amount of River Hydro investment was deferred and, as
19 such, is not presented on the Company's Exhibit A-12 (RTB-3), Schedule B-5.2. In
20 addition, the entire amount of investment for the Covert Long-Term Service Agreement
21 ("LTSA") extra work was disallowed. The disposition of the other capital projects which
22 are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2 is provided below:

23 Below is a list of projects for which the Company either removed or did not reflect
24 in the revenue requirement due to their COD being beyond the test year:

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Project Description	Projected Amount
Solar - 2021 Bid Event (Muskegon Solar) (250 MW)	\$ 141,387
Solar - 2022 Bid Event (Spring Creek)	\$ 108,185
Armstrong Battery Energy Storage System (IIJA Grant App)	\$ 6,341

Below is a list of projects whose projected bridge period costs were reduced or deferred by the Company and their projected amounts approved in the final order in Case No. U-21585 were less than \$1 million:

Project Description	Projected Amount ('000)	Reduced Amount ('000)
Covert Purchase of site spare generator stepup transformer	\$ 1,000	\$ (27)
Covert Cooling Tower Gearboxes	\$ 1,162	\$ 872
Covert SCR/CO Catalyst Replacement - Unit 2	\$ 1,042	\$ 142
Covert SCR/CO Catalyst Replacement - Unit 3	\$ 1,042	\$ 142
Karn Unit 3 Combustion Air Heater	\$ 2,200	\$ 214
Ludington lower penstock expansion joint Chamber water stop replacement	\$ 2,716	\$ 556

Below is a discussion of the remaining million-dollar projects whose actual 2024 capital expenditures were less than projected:

- Covert Units 1 through 3 Emerson Digital Control System (“DCS”) Evergreen (\$1,041,250). The projected 2024 spend for this project was only \$551,500 with the largest portion of the spend reflected in 2025 including the last two months of the bridge period. The actual spend in 2024 was \$530,441 so the actual spend is relatively on target. The remaining spend of \$2,156,101 in the bridge period and \$967,800 in the test year will complete the project;
- Jackson Long Term Service Agreement Extra Work Expected (\$1,366,114). During 2024, the Company spent a total of \$330,371 on this project, primarily due to moving S2 Nozzle Assy work from 2024 to 2025 because of the delay in material delivery from General Electric. \$2,115,001 is planned for the bridge period ending April 30, 2026, and only \$0.315 million is planned for the test year ending April 30, 2027;
- Zeeland Phase I Gas Turbine Advanced gas path replacement and axial fuel staging (\$8,631,164) and LTSA Extras not included in the contract. The total spend for these projects and the long-term service agreement in 2024 was \$21,506,968. The total projected amount for these three projects for the 14-month bridge period was \$29,505,861 with \$9,941,250 of that projected amount reflected in January and February of 2025. As such, the actual spend for all the work associated with the LTSA was greater than the projected amounts;
- Karn Unit 4 DCS Evergreen (\$1,449,204). The Company spent \$125,388 in 2024 versus the projected 2024 amount of \$1,363,000. The Company underspent on the project because it didn’t employ Emerson Field Engineering Service time, rather the Company completed many of the items internally and, therefore, avoided a portion of the investment; and

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- Ludington 1-6 distributed control system control relay replacement (\$1,623,526). During 2024 the Company spent \$670,551 of the total 2024 projected amount of \$1,214,360. The remaining bridge period amount was forecast to be spent in January and February of 2025. The Company is projected to spend \$3,608,477 in the 16-month projected bridge period and \$2,906,676 in the projected test year. The project was intentionally delayed in order to align it with the large corrective project outage schedule. This project was originally scheduled to execute in 2025 through 2027. The Company's current plans are to execute the project in 2026 through 2029 in order to minimize the impact on unit availability.

Q. Please discuss the 2024 capital projects that were not included in Case No. U-21585, Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, that are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7.

A. The disposition of these capital projects is presented below:

- Covert Heat Recovery Steam Generator ("HRSG") Expansion Joint Replacements (\$1,284,244). There was no projected amount for 2024, however the work was required as a result of equipment (seal) failure. The seals for all three units failed, resulting in hot flue gas blowing out of the unit. This presented a safety issue, as there were areas around the units that a person could not safely approach due to excessive heat and exhaust gas inhalation. In addition, the site was also experiencing issues where some of the instrumentation cables were failing due to the excessive heat melting their insulation. Finally, because of the seal failures, the insulation failed in the floor sections of the duct where these penetrations are located. To replace the expansion joints and not address the insulation would have resulted in a quick recurrence of the expansion joints failing. The work to remove liners and replace the insulation was more costly than the expansion joint work, but a necessary part of the overall replacement. Project closeout for this project will be completed in the bridge period as discussed later in this direct testimony;
- Covert LTSA Extra Work Unit 2 (\$1,339,561). The projected amount for 2024 was \$750,000 and the amount projected for 2025 was \$12,576,300. The actual amount came in higher due to pulling some of the investment forward, thereby reducing the projected amount for the 16-month bridge period to \$12,153,320. This project will be discussed in more detail later in this direct testimony;
- Jackson Units 1-6 Feedwater ("FW") Desuperheater Valve (\$1,871,081). The scope of this project was to install FW control valves and separate lance spray nozzle assemblies that spray small amounts of water into steam flow continuously. The HRSG 1-6 superheat ("SH") Steam Desuperheater FW valves have had very short life spans since original construction. There were several issues that caused the valves to wear out quickly. The valves inherently

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1 cycled frequently open and closed due to the boiler running close to high
2 pressure (“HP”) Steam Outlet temperature setpoint at gas turbine baseload,
3 without duct firing. This has been reduced recently by a study completed by
4 engineering and GE to allow the HP Steam temperature to be increased from
5 the original 750 degrees Fahrenheit up to 770 degrees Fahrenheit. This change
6 did cause the valves to cycle open/close less frequently, but it did not result in
7 a substantial improvement in valve life. The brunt of the wear is absorbed by
8 the High Pressure Feedwater Autoblock valve, which when it begins to leak by,
9 causes the SH Steam temperature to fall. The HP FW Control Valve wears out
10 quickly as well. Typically, when this occurs the leak by accelerates quickly to
11 the point which the manual HP FW isolation valve upstream must be closed
12 when the unit is not duct firing to maintain adequate superheated steam
13 temperature. The projected amount for 2024 was \$828,100. However, this
14 projected cost was not based upon a solicitation. Upon receiving proposals it
15 was learned that the lowest bid amount was approximately \$1 million higher
16 than the projected cost. The project payback is still relatively short as the plant
17 was experiencing approximately three failures annually at a cost greater than
18 \$1 million;

- 19 • Zeeland Site Spare Generator Step-Up (“GSU”) (2,039,715). The scope of this
20 project is to purchase a spare GSU. The projected spend was \$589,607 for the
21 bridge period and \$2,340,637 for the test year. The project is described in more
22 detail later in this direct testimony; and
- 23 • Zeeland Phase 2 599 and 699 345 kV breaker replacement (\$1,855,883). The
24 scope of this project is to replace the 599 and 699 circuit breakers with a type
25 which does not exhibit the failure modes exhibited by the existing design. The
26 existing breakers have a critical design flaw such that an individual pole or poles
27 may not latch open when required. The pole’s failure to latch open has the
28 potential to result in lost generation, loss of power to the entire Zeeland
29 Substation, and/or equipment damage. The projected amount for 2024 was
30 \$319,559 and was originally scheduled for execution in 2023. However, it was
31 pushed to 2024 for various reasons including the fact that the breaker delivery
32 and GSU project delivery missed their 2023 installation targets.

33 The following four projects were all implemented to support the separation of Karn
34 Units 1 and 2 from Karn Units 3 and 4. This unit separation work was presented in the
35 Company’s 2021 IRP and the Company’s 2023 Electric Rate Case No. U-21389 but was
36 not appropriately reflected in the Company’s 2024 Electric Rate case, Case No. U-21585
37 as it was erroneously reflected as decommissioning/cost of removal. Each of these projects

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were required to operate Karn Units 3 and 4 independent of Karn Units 1 and 2 following their retirement on May 31, 2023.

- New Electrical System from Weadock Sub for Karn 3 and 4 (\$1,523,648);
- Discharge Line Reroute for K 3 and 4 Sump Water (\$1,905,159);
- New building to house new fire water system (\$1,019,275); and
- New 46kV to 4160 transformer to re-power facilities (\$3,065,403).

The projected spend for the bridge period for the following two projects was less than \$1 million in the Company's original filing but the projected spend was updated to be greater than \$1 million and presented in Staff Exhibit No. S-16.1 (RDB-2), page 1 of 2.

- Karn 3&4 Tank Farm Heating Line Replacement (\$1,216,552); and
- Netmation (MHPSA Operating System & 4S) - Unit 1-3 (\$5,046,654).

**PROJECTED 16-MONTH BRIDGE PERIOD CAPITAL
EXPENDITURES**

Q. How does the projected 16-month bridge period capital expenditure of \$275.408 million compare to the amount of capital requested by the Company in Case No. U-21585 for 2025?

A. The 16-month bridge period projected capital expenditure amount of \$275.408 million compares favorably with the \$724.728 million for the 14-month period beginning January 1, 2025 through February 28, 2026. While the difference is quite large, it is important to call out that the Company's initial request in Case No. U-21585 for the 14-month period beginning January 1, 2025 through February 28, 2026 included \$373.076 million for three solar projects which the Company has since removed and moved to its Renewable Energy Plan Case No. U-21816 and also included \$96.582 million for River Hydro investments. In addition, a portion of the projected BESS investment was

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1 moved out beyond the test year in Case No. U-21585 and, as a result, that investment had
2 no material impact on the revenue requirement used to establish rates. A detailed
3 discussion of the BESS projects is presented in Company witness Clark's direct testimony.
4 A compilation of the 16-month bridge period projects which have projected capital
5 expenditure amounts greater than \$1 million is presented on Exhibit A-12 (RTB-3),
6 Schedule B-5.2, page 8, and an explanation of the project changes is described in more
7 detail later in this direct testimony.

8 **Q. How does the compilation of 16-month bridge period capital projects on Exhibit A-12**
9 **(RTB-3), Schedule B-5.2, page 8, compare with the test year capital projects reflected**
10 **on Case No. U-21585, Exhibit A-12 (RTB-3), Schedule B-5.2, page 9?**

11 A. A comparison of the 16-month bridge period capital projects on Exhibit A-12 (RTB-3),
12 Schedule B-5.2, page 8, with the test year projects reflected on Case No. U-21585, Exhibit
13 A-12 (RTB-3), Schedule B-5.2, page 9, reveals that there are 12 projects on Exhibit A-12
14 (RTB-3), Schedule B-5.2, page 8, which were not reflected on Case No. U-21585, Exhibit
15 A-12 (RTB-3), Schedule B-5.2, page 9. In addition, there were 11 projects for the
16 12-month period ending February 30, 2026 that were reflected on Case No. U-21585,
17 Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, that are not presented on Exhibit A-12
18 (RTB-3), Schedule B-5.2, page 8. The River Hydro projects were not considered in this
19 evaluation due to their removal.

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Q. Please discuss the test year capital projects that were included on Case No. U-21585, Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, that are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8.

A. The following projects are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, due to the fact that the projected bridge period capital expenditure amounts are now less than \$1 million or the project is not being pursued in the bridge period. The disposition of these capital projects is presented in the table below:

Site	Project	Disposition
Covert	Cooling Tower Gearboxes	project spend reduced in U-21585
Covert	Unit 1 - LTSA Capital - Extra work not included in contract	Project disallowed in U-21585
Covert	Office Space Consumers Energy Warehouse with Loading Dock	Project disallowed in U-21585
Karn 4	Karn 4 Replacement of Ductwork Insulation and Lagging	Project disallowed in U-21585
Zeeland	Generator Rewinds	Inspection determined work not required
Ludington	Ludington Intake Gate and Gate House Mechanical Replacement	\$1.732 million in bridge period and test year
Ludington	Station Power Transformer Life Cycle Management	\$1.407 million in bridge period and test year
BESS	Armstrong Battery Energy Storage System (IJA Grant App)	Project COD delayed to beyond test year
Solar IRP	Solar - 2021 Bid Event (Muskegon Solar) (250 MW)	Moved to the Renewable Energy Plan
Solar IRP	Solar - 2022 Bid Event (Spring Creek)	Moved to the Renewable Energy Plan
Solar IRP	Solar - 2020 Bid Event (Washtenaw Solar) (150 MW)	Moved to the Renewable Energy Plan

Q. Please identify the 16-month bridge period capital projects that were not included on Case No. U-21585, Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, that are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8.

A. The bridge period capital projects that were not included on Case No. U-21585, Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, are presented in the table below:

Line No.	Site	Project Description
1	Covert	Load Commutated Inverter Static Frequency Converter
2	Jackson	Purchase of site spare GSU
3	Jackson	LM6000 ESN 191-306 HP Turbine S2 Nozzle replacement
4	Jackson	LTSA Capital - Extra work not included in contract
5	Zeeland	Unit 5 GSU Transformer
6	Karn 3	Combustion Air Heater Replacement
7	Karn 4	Combustion Air Heater Replacement
8	Karn 4	ID Fan Inlet Damper Replacements
9	Ludington	Replace Lower Penstock Expansion Joint
10	Ludington	Station Water Dschrg Isolation Valve
11	Admin	Wastewater Treatment System

The basis for these projects will be discussed in more detail later in this direct testimony.

1 **Q. Is the projected capital expenditure amount of \$275.408 million for the 16-month**
2 **bridge period ending April 30, 2026, on Exhibit A-12 (RTB-3), Schedule B-5.2, page 1,**
3 **column (e), consistent with the Company's generation asset strategy?**

4 A. Yes. Based upon a review of the projected capital expenditure presentation on
5 Exhibit A-12 (RTB-3), Schedule B-5.2, pages 2 and 3, lines 1 through 84, column (h),
6 \$70.614 million will fund BESS projects, \$171.787 million of that total capital expenditure
7 amount will be used at the Company's natural gas generating facilities which includes
8 Covert, Jackson, Zeeland, and Karn Units 3 and 4. In addition, \$15.225 million will fund
9 various projects at the LPS facility. With the exception of the BESS projects, a detailed
10 discussion of the various projects for each generating unit or group of generating units will
11 be provided later in this direct testimony. The BESS projects will be discussed in the direct
12 testimony of Company witness Clark.

13 **PROJECTED TEST YEAR CAPITAL EXPENDITURES**

14 **Q. Is the projected capital expenditure amount of \$188.638 million for the test year**
15 **ending April 30, 2027, on Exhibit A-12 (RTB-3), Schedule B-5.2, page 1, column (f),**
16 **consistent with the Company's generation asset strategy?**

17 A. Yes. Based upon a review of the projected capital expenditure presentation on
18 Exhibit A-12 (RTB-3), Schedule B-5.2, pages 2 and 3, lines 1 through 84, column (j),
19 \$26.392 million will fund BESS projects, \$137.913 million of that total capital expenditure
20 amount will be used at the Company's natural gas generating facilities which includes
21 Covert, Jackson, Zeeland, and Karn Units 3 and 4. In addition, \$13.282 million will allow
22 the Company to complete various regulatory, reliability, and infrastructure projects
23 necessary to support the 50-year license extension at Ludington granted by FERC in 2019.

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1 Except for the BESS projects, a detailed discussion of the various projects for each
2 generating unit or group of generating units will be provided later in this direct testimony.

3 The BESS projects will be discussed in the direct testimony of Company witness Clark.

4 **Campbell Units 1, 2, and 3**

5 **Q. Please explain the Company's projected capital investment for the 16-month**
6 **projected bridge period ending April 30, 2026 and projected test year ending April**
7 **30, 2027 for Campbell Units 1, 2, and 3.**

8 A. The Company does not plan to invest any capital in the Campbell units during the bridge
9 period or test year, as reflected on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, lines 1
10 and 8. As presented on Exhibit A-43 (RTB-4), page 3, lines 1 and 2, and as discussed later
11 in this direct testimony, the Company has projected modest amounts of major maintenance
12 to ensure that these units were able to operate through their retirement date of May 31,
13 2025.

14 **Covert Plant**

15 **Q. Please explain the Company's projected capital investment for the 16-month**
16 **projected bridge period ending April 30, 2026 and projected test year ending April 30,**
17 **2027 for Covert.**

18 A. The Company plans to invest a total of \$67.545 million in the 16-month bridge period and
19 \$61.443 million in the test year at the Covert Plant. These capital investments will be
20 facilitated by nine-day outages at Covert Units 1 through 3 in the spring and fall of 2025
21 as well as longer unit outages for major inspections. Covert Unit 1 has a 59-day outage
22 scheduled to begin on September 1, 2025, Covert Unit 3 has a 59-day outage scheduled to

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begin on March 15, 2026, and Covert Unit 2 had a 59-day outage scheduled that began on March 1, 2025.

Q. Please explain the Company's projected capital investment for the 16-month bridge period ending April 30, 2026 for the Covert Plant.

A. The Company plans to invest a total of \$67.545 million in the bridge period on the Covert Plant, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 43, column (h).

Q. What is the basis for the projected \$67.545 million capital investment in the 16-month projected bridge period?

A. The projected \$67.545 million capital investment in the projected bridge period will fund numerous projects at the Covert Plant. Seven of these projects are greater than \$1 million, and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 1 through 7.

The basis for these six projects is described below:

- Load Commutated Inverter ("LCI") Static Frequency Converter ("SFC") Replacements (\$1,305,000). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Purchase of site spare GSU (1,500,000). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Netmation (Operating System & 4S) – Units 1 through 3 (\$2,921,689). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Covert Units 1 through 3 Emerson DCS Evergreen (\$2,156,101). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert; and
- Covert Plant LTSA (\$26,246,048). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Covert Unit 2 LTSA extra work (\$12,153,320). The LTSA extra work is defined as the work that is not covered under normal planned maintenance in

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the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items not covered under the LTSA that need to be addressed are labor and material to replace the following: blading, ammonia delivery system, Selective Catalytic Reduction (“SCR”) catalyst, turbine rotors, cooling towers, and turbine cooling air cooler. The major inspection on Covert Unit 2 began on February 1, 2025, and major work includes generator inspection, replacement of the generator hydrogen seals, generator rewedge, diaphragm repairs, steam turbine and generator bearing repairs, and HP stop and control valve disassembly, inspection, cleaning, and repair. The Company’s LTSA with Mitsubishi Electric Power Products, Inc. (“MEPPI”) does not cover this scope of work; and

- Covert Unit 3 LTSA extra work (\$9,009,801). The LTSA extra work is defined as the work that is not covered under normal planned maintenance in the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items not covered under the LTSA that need to be addressed are labor and material to replace the following: blading, ammonia delivery system, SCR catalyst, turbine rotors, cooling towers, and turbine cooling air cooler. This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert.

The following projects are less than \$1 million, but are important to reliability:

- Covert Unit Cooling Tower Gearboxes (\$675,000). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Gas Compressor Controls Replacement (Programmable Logic Controller (“PLC”) replacement) (\$144,000). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- HRSG Expansion joint replacement (\$450,000). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Balance of Plant (“BOP”) Valves – Covert Units 1 through 3 (\$1,105,200 total). These projects span the 16-month bridge period and the test year, and their basis is included in my discussion of the test year capital projects for Covert;
- Gas turbine generator and steam turbine generator auto voltage regulator – Covert Units 1 and 3 (\$750,000 each). These projects span the 16-month bridge period and the test year, and their basis is included in my discussion of the test year capital projects for Covert;

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- Covert Units 1 through 3 MTX High Voltage Bushing – GSU (\$1,379,700 total). These projects span the 16-month bridge period and the test year, and their basis is included in my discussion of the test year capital projects for Covert;
- Linear Variable Differential Transformers (“LVDT”) Positioning Sensor – Unit 2 Fuel Control Valves (\$715,500). The scope of this project is to replace the Yokogawa 5516 mechanical type position sensors with LVDTs. The replacement is to include the following devices, Main “A” pressure control fuel valve sensor, Main “B” pressure control fuel valve sensor, Main flow control fuel valve sensor, Pilot pressure control fuel valve sensor, and the Pilot flow control fuel valve sensor and compressor bypass actuator. The benefits of this project include reduced maintenance, improved accuracy, and higher long-term reliability due to the removal of the mechanical linkages and converting to a non-contact mechanism;

The Covert Mitsubishi Power Gas turbines are equipped with Yokogawa 5516 mechanical linkage type position sensors. The Yokogawa position sensors are used to detect the position of the fuel control valves, bypass valve actuators, and the Inlet Guide Vanes. These valves and their position are critical as they control turbine output which allows more load on the generator and meets load demand. The Yokogawa 5516 position sensors are obsolete, and Yokogawa has announced that the 5516 position sensors are no longer manufactured as of March 31, 2015, no longer supported, and parts are no longer available. Mitsubishi Power recommends eliminating the Yokogawa mechanical linkage position sensors;

- LVDT Positioning Sensor – Unit 1 Fuel Control Valves (\$253,500). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- LVDT Positioning Sensor – Unit 3 Fuel Control Valves (\$253,500). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Small Site Capital (\$380,000). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Covert Base Outage Capital (\$774,000). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages;
- 3A Circ Pump/Motor Replacement (\$630,000). The Circulating Water Pump Replacement project is a critical initiative aimed at replacing the Unit 3A circulating water pump and motor, which have been in operation for over 20 years and have reached the end of their service life based on failure data

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compiled from the rest of the circulating water pumps on site. This replacement is necessary to maintain plant reliability and avoid potential unit derates;

- Covert – high energy piping surveillance (“HEPS”)/ flow accelerated corrosion (“FAC”)/ deaerator and its storage tank (“DAST”) Inspections (\$327,500). This project aims to bring the Covert site into compliance with existing corporate governance on G-A-313, G-A-314, and G-A-315 programs. Compliance with these programs ensures the safe operation of the site and provides outage scheduling flexibility by transitioning from a 12-month operating certificate to 2-year and 3-year operating certificates. The project is essential to maintain the ability to implement 2-year and 3-year operating certificates. Failure to perform the required inspections would limit the unit to a 12-month operating certificate, necessitating a full inspection before the unit can be certified to operate;
- Units 1,2,3 North American Electric Reliability Corporation (“NERC”) Relay Replacements and Test Switch Installation (\$685,712). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Excitation Replacement (\$263,833). The scope of this project is the replacement of the steam turbine exciters. The existing excitation equipment is obsolete, and the gas turbine exciters have already been replaced. A failure of the steam turbine exciter could lead to both generators on the unit being out of service until replacements can be found with a typical lead time of 18-24 months; and
- Twenty-five additional projects at Covert totaling \$3.043 million which support safety, security, and reliability, with each project representing \$243,000 or less in capital expenditures. These projects include gas turbine wheel flame detectors, gas turbine evaporator media, plant fuel gas bypass system, ammonia fan replacements, actuator replacements, and unit 1 Power Distribution Center (“PDC”) battery replacement.

Q. What is the basis for the projected \$61.443million capital investment in the projected test year?

A. The projected \$61.443 million capital investment in the projected test year will fund numerous projects at the Covert Plant. Six of these projects are greater than \$1 million, and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 1 through 6. The basis for these projects is described below:

- LCI SFC Replacements (\$2,610,000). The scope of this project is to replace the two SFCs which are both original to the plant’s construction in 2001. The

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1 replacement of the SFC controls is required to mitigate the significant risk of
2 failure due to obsolescence, ensure operational reliability, and align with
3 manufacturer recommendations. The Covert Generating Station Static
4 Frequency Converter Controls Replacement project is essential to address
5 significant operational and reliability issues stemming from the obsolescence
6 of the current SFC controls. The concept approval document for this project is
7 attached as Exhibit A-46 (RTB-7);

- 8 • Purchase of site spare GSU transformer (\$5,910,000). Covert Generating
9 Station consists of three gas turbine powered plants and three steam turbine
10 powered plants placed in a one-on-one combined cycle configuration. The
11 units transmit their power to the grid via GSU transformers. Each gas turbine
12 powered unit feeds the secondary winding of a three-winding transformer,
13 while the associated steam powered unit feeds the tertiary winding of the
14 transformer. The GSU is rated for 500 MVA with forced oil and forced air. If
15 a GSU were to fail, then the associated turbines would not be able to transmit
16 power and would not be able to generate market value for Consumers Energy
17 and its customers. The lead time for a GSU is currently three-to-four years and
18 spare units at other facilities typically do not exist, especially for this more
19 unique design application;

20 This project provides a spare GSU for Covert which 1) Greatly reduces unit
21 downtime in the event of GSU issues or failure requiring removal and lowers
22 the total financial losses in such events; 2) Allows for easier engineering design
23 and planning to install a spare or replacement GSU ahead of any emergent
24 installation needs; 3) Mitigates potential issues from installing GSUs not
25 specifically designed for this location, system, or application and/or doing it
26 multiple times in a short time period; 4) Would allow for Consumers Energy to
27 enter lease agreements with other utilities who may be in need of a spare to
28 recover some costs of the spare purchase over time; and 5) The oil analysis of
29 Covert transformers revealed the presence of chemicals for corrosive
30 sulfur. Mitigating actions are being taken, however, this failure mode puts these
31 transformers at increased risk of failure. The concept approval document for
32 this project is attached as Exhibit A-47 (RTB-8);

- 33 • Netmation (Operating System & 4S) (\$8,843,713). The Covert gas generating
34 station, operational since 2004, faces critical challenges with its outdated
35 control systems. These challenges impact both operational efficiency and
36 cybersecurity, necessitating an urgent upgrade to modern standards. The scope
37 of this project is an extensive upgrade of the Covert Mitsubishi Turbine Control
38 System to the latest version of Netmation, which includes the replacement of
39 hardware, input/output ("I/O") modules, servers, workstations, network
40 switches, and software to the latest architecture. The concept approval
41 document for this project is attached as Exhibit A-48 (RTB-9);
- 42 • Covert Plant LTSA (\$18,811,878). This is the capital portion for Mitsubishi
43 negotiated services that cover the planned normal maintenance of each

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1 generating unit. The projected capital expenditures are based upon variable fees
2 paid to Mitsubishi for maintenance services which are based on an Effective
3 Fired Hour basis pursuant to the LTSA. Unlike the GE LTSAs for the Jackson
4 and Zeeland plants, there are no milestone payments associated with the fee
5 structure for the Mitsubishi LTSA. Based on the OEM's operating and
6 historical experience, if the Company executes the normal planned maintenance
7 and inspections according to the recommended schedules, the Company will
8 mitigate unexpected pre-mature failures of the equipment. This will help
9 maximize availability and, as a result, optimize customer value for the site.
10 Normal maintenance will ensure the Company continues reliable operation of
11 the units. During the bridge period and test year, the Company will be
12 conducting major inspections on all three generating units, and a portion of the
13 work to be performed is not covered in the LTSA, rather it is covered in the
14 LTSA extra work as described below;

- 15 • Covert Unit 1 LTSA extra work (\$9,524,986). The LTSA extra work is defined
16 as the owner's obligations per the LTSA division of responsibility for work
17 performed by the OEM. The Covert LTSA outlines a division of responsibility,
18 with many items falling under the owner's responsibility to purchase or furnish
19 to the OEM for completing the work scope designated by the LTSA. These
20 items include, but are not limited to: (i) Required crane rentals to support
21 rigging and moving various pieces and parts, (ii) Office and break trailer rentals
22 for personnel onsite during the outage, (iii) Restroom and wash facilities for
23 onsite personnel supporting the outage, (iv) Drinking water, (v) Trailer rentals
24 for moving parts and pieces to designated laydown areas, (vi) Support structure
25 assembly for the generator field when it is removed from the generator,
26 (vii) Removal of the building wall for generator field removal,
27 (viii) Scaffolding and insulation services, (ix) Generator electrical testing.
28 These items are not covered by the LTSA but are necessary to support the LTSA
29 work scope. All parts required for the generators and the steam turbine are not
30 covered by the LTSA but are essential for executing the outage. Some of these
31 parts are consumable, while others are deemed unusable per inspections
32 performed during the outage. Any parts damaged during disassembly that are
33 required to perform the LTSA scope of work would also be replaced. Examples
34 include bolting, valve assemblies, gaskets, thrust shim plates, and steam turbine
35 packing. The labor to install packing and the resulting steam path alignment
36 activities are also not covered by the LTSA but are necessary to perform the
37 work scope per the LTSA. Additionally, once the steam turbine, gas turbine,
38 and generators are disassembled and inspected, historical outage experience and
39 industry experience indicate that many items will need to be repaired that are
40 not covered by the LTSA. These items include, but are not limited to: (i) Steam
41 turbine rotor repairs, (ii) Steam turbine diaphragm repairs, (iii) All bearing
42 repairs for the gas turbine, steam turbine, and generators, (iv) Hydrogen seal
43 repairs, (v) Steam turbine shell repairs, (vi) Collector ring machining, and
44 (vii) Compressor hook fit repairs. The major inspection for Covert Unit 1
45 begins on September 1, 2026, and ends on October 30, 2026. Consumers
46 Energy used the historical expenses for these items incurred by the previous

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owner of the plant and escalated the amounts for inflation. Additionally, current plant performance and previous outage reports were reviewed to predict as close as possible any additional work scope that would be required to restore the units to necessary reliability and performance standards while reducing any risk to the unit as much as practical. Consumers Energy also predicted that some repairs that were deferred by previous owners will have degraded to a point that repairs are now prudent. These were all combined to establish the Company's first outage scopes and budgets for the Covert units; and

- Covert Unit 3 LTSA extra work (\$4,093,234). The LTSA extra work is defined as the owner's obligations per the LTSA division of responsibility for work performed by the OEM. The Covert LTSA outlines a division of responsibility, with many items falling under the owner's responsibility to purchase or furnish to the OEM for completing the work scope designated by the LTSA. These items include, but are not limited to: (i) Required crane rentals to support rigging and moving various pieces and parts, (ii) Office and break trailer rentals for personnel onsite during the outage, (iii) Restroom and wash facilities for onsite personnel supporting the outage, (iv) Drinking water, (v) Trailer rentals for moving parts and pieces to designated laydown areas, (vi) Support structure assembly for the generator field when it is removed from the generator, (vii) Removal of the building wall for generator field removal, (viii) Scaffolding and insulation services, (ix) Generator electrical testing. These items are not covered by the LTSA but are necessary to support the LTSA work scope. All parts required for the generators and the steam turbine are not covered by the LTSA but are essential for executing the outage. Some of these parts are consumable, while others are deemed unusable per inspections performed during the outage. Any parts damaged during disassembly that are required to perform the LTSA scope of work would also be replaced. Examples include bolting, valve assemblies, gaskets, thrust shim plates, and steam turbine packing. The labor to install packing and the resulting steam path alignment activities are also not covered by the LTSA but are necessary to perform the work scope per the LTSA. Additionally, once the steam turbine, gas turbine, and generators are disassembled and inspected, historical outage experience and industry experience indicate that many items will need to be repaired that are not covered by the LTSA. These items include, but are not limited to: (i) Steam turbine rotor repairs, (ii) Steam turbine diaphragm repairs, (iii) All bearing repairs for the gas turbine, steam turbine, and generators, (iv) Hydrogen seal repairs, (v) Steam turbine shell repairs, (vi) Collector ring machining, and (vii) Compressor hook fit repairs. The major inspection on Covert Unit 3 begins on March 15, 2026, and major work includes generator inspection, replacement of the generator hydrogen seals, generator rewedge, diaphragm repairs, steam turbine and generator bearing repairs, and HP stop and control valve disassembly, inspection, cleaning, and repair. The Company's LTSA with MEPPi does not cover this scope of work. Consumers Energy used the historical expenses for these items incurred by the previous owner of the plant and escalated the amounts for inflation. Additionally, current plant performance and previous outage reports were reviewed to predict as close as

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possible any additional work scope that would be required to restore the units to necessary reliability and performance standards while reducing any risk to the unit as much as practical. Consumers Energy also predicted that some repairs that were deferred by previous owners will have degraded to a point that repairs are now prudent. These were all combined to establish the Company's first outage scopes and budgets for the Covert units.

The following projects are less than \$1 million, but are important to reliability:

- Gas Compressor Controls Replacement PLC replacement (\$576,000). Gas Compressors (two in total) operate using a local control network consisting of a human machine interface ("HMI") (Panel View 1000) and Allen Bradley PLC five controllers. This equipment has reached end of life and replacements are no longer available. The Covert site currently has one failed board in service. This project would utilize existing panels and replace the equipment with an Allen Bradley ControlLogix solution and PanelView Plus 7;
- HRSG Joint replacement (\$360,000). The scope of this project is to replace the vertical round expansion joint between the combustion turbine and the building and the HRSG. The Covert Generating Station HRSG expansion joint replacement project addresses the critical issue of aging expansion joints on all three units. These joints have a design life of 6-8 years and are typically replaced during turbine major outages. However, the existing expansion joints will be at least four years beyond their design life if replacement is delayed until the next major outage. This significantly increases the probability of failure, which could start as a small tear detectable by thermography but could also result in a large rip. Such failures would allow exhaust gases to bypass the stack and environmental monitoring equipment, releasing high-temperature gas inside the building, posing a personnel hazard and significantly impacting overall heat rate efficiency. A failure of the expansion joint could force the unit offline for 30 days until it is replaced, potentially resulting in a month of downtime if the failure is severe;
- Plant Replace Sulfuric Sodium Hypo and Building (\$600,000). The project involves replacing the existing sulfuric acid and sodium hypochlorite dosing systems and the building housing these systems at Covert. The current sodium hypochlorite system, in operation since 2004, has experienced over 60 documented failures, leading to chemical releases and hazardous cleanup situations. The system has surpassed its expected life cycle, posing increased risks of employee exposure, injury, and environmental contamination. The primary objective is to replace the aging sodium hypochlorite and sulfuric acid dosing systems and their housing structure to mitigate the risks associated with chemical spills and exposure to hazardous vapors. By separating the dosing systems, the potential for a combined spill creating chlorine gas is significantly reduced;

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- Unit 1 Cooling Tower Gearboxes (\$675,000). The Covert Generating Station Cooling Tower Fan Gearbox Replacement Project addresses critical operational issues stemming from the end-of-life status of gearboxes after over 20 years of service. These gearboxes are essential for cooling tower fan operations, affecting the station's overall efficiency and reliability. The scope of this project is to replace the existing cooling tower gearboxes with gearboxes from the same manufacturer, an alternative that avoids additional modifications. Covert operates three 6-cell cooling towers corresponding to each of its units. These cooling towers play a crucial role in the station's operational efficiency by facilitating the removal of residual heat from circulating water. This process is essential after the water has been utilized for condensing steam produced by the steam turbines. Operational challenges with the gearboxes include increased gearbox failures, inadequate heat removal due to malfunctioning cooling tower fans, and obsolete motor starters; and
- Covert Units 1 through 3 Emerson DCS Evergreen (\$967,800). The scope of this project is to upgrade the DCS to the latest version in order to enhance security, gain compliance with enterprise standards, and achieve technological advancement. Covert, which has been operational since 2004, faces significant challenges with its Emerson Ovation DCS. The system's obsolescence, cybersecurity risks, and operational inefficiencies necessitate an urgent upgrade to the latest version to enhance reliability, security, and compliance with regulatory standards. The DCS that controls all equipment in the plant (along with the Mitsubishi gas turbine controls), is Emerson Ovation DCS. It was upgraded about 10 years ago to the current version. Emerson Ovation version 3.5.1 is no longer supported by Emerson or Microsoft. The Emerson Ovation version 3.5 system entered a retired status in June 2019. The Windows operating systems that are used by this version of Ovation are Windows 7 and Windows Server 2008R2. Microsoft ended extended support of Server 2008R2 in January 2020.

The generation plant control systems are an important part of the nation's Critical Infrastructure and fall under NERC Critical Infrastructure Protection requirements. To keep the Company's control systems secure, Consumers Energy must patch the operating systems and applications that run its plants. The Company is no longer able to patch and maintain these operating systems, such as Microsoft Windows, or applications, such as Ovation, when they are no longer supported by the manufacturers. The systems at Covert do not meet corporate cybersecurity standards and are operating with security exception to the Company's standards.

The cybersecurity tools (Power Water Cybersecurity Suite ("PWCS")) being utilized for the Covert control network device patching and antivirus protection require replacement to allow continued patching and protection with a new DCS version. The current version of PWCS is nearing the end of support and requires updating to allow support of the latest Ovation versions.

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1 The BOP control is achieved with the Ovation DCS. Its architecture is
2 comprised of controller and operator “drops” (processors and PCs) that provide
3 the control of the equipment with I/O modules. Some of these I/O modules are
4 in the same electrical cabinets that contain the “controller drops” (processors).
5 Other I/O is in “remote” electrical cabinets, away from the “controller drops.”
6 The existing plant control is comprised of many remote I/O cabinets throughout
7 the site. The communication modules to these cabinets have experienced
8 failures in the past that can trip the generating units offline. Power supplies in
9 the Ovation cabinets have reached the end of their recommended life and need
10 to be replaced. The architecture and components need to be upgraded and
11 replaced with the latest Ovation design.

12 The main controller drop that operates a large part of the BOP equipment
13 has had equipment and data link controls added to it over the years. It controls
14 equipment for all three (3) generating units. The controller drop needs to have
15 part of its I/O and logic split off to new controller drops. The partitioning of I/O
16 to other drops should allow the upgrade and maintenance procedures to occur
17 and reduce the need of a site outage to perform these activities. Risk to unit
18 trips should be reduced to individual generating units instead of all units on the
19 site. The concept approval document for this project is attached as Exhibit A-49
20 (RTB-10);

- 21 • Flame Detectors for Gas Turbine Wheel temperature Digital replacement
22 (\$273,000 total). The scope of this project is to replace the existing mechanical
23 flame detection system with a digital flame detection system. The existing
24 system is obsolete and has reliability issues that a new digital system would
25 resolve;
- 26 • Balance Of Plant Valves – Unit 1 (\$450,000). The scope of this project is the
27 repair and/or replacement of balance of plant valves. Project is to overhaul the
28 U1 HRS-PV105 and LPS-PV110 steam bypass valves. PV105 was last rebuilt
29 in 2017 and PV110 has never been overhauled. These valves are used for
30 startup, shutdown and unit trips to bypass steam to the condenser and
31 experience extreme service conditions that should be considered for overhaul
32 every 7 to 10 years. These projects should align with major outages to allow for
33 ample time to disassemble, inspect and repair. Overhauling the valves results in
34 reliable dependable service as these valves are critical to starting up and
35 shutting down the unit. They must also operate during trip conditions to prevent
36 an overpressure event and potential damage to other components;
- 37 • Balance Of Plant Valves – Unit 3 (\$450,000). The Scope of this project is to
38 overhaul the HRS-PV105 and LPS-PV110 steam bypass valves. PV105 was
39 last rebuilt in spring 2019 and PV110 has never been overhauled. These valves
40 are used for startup, shutdown, and unit trips to bypass steam to the condenser
41 and experience extreme service conditions that should be considered for
42 overhaul every 7 to 10 years;

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- Gas turbine generator and steam turbine generator auto voltage regulator – Covert Units 1 and 3 (\$600,000 each). The current MEC5000 digital automatic voltage regulators (“D-AVR”), which are over 20 years old, pose a substantial risk of failure. Any failure in these D-AVRs renders both the gas turbine generator (“GTG”) and steam turbine generator (“STG”) on the affected unit unavailable, leading to extended outages and significant financial impacts. The OEM has indicated a lead time of 18-24 months for new D-AVRs;
- AVR parts, further exacerbating the potential downtime. The Covert Generating Station, operational since 2004, faces significant challenges with its aging MEC5000 D-AVRs. These regulators, critical for controlling the generators' response to load demand, are obsolete and no longer supported by the OEM, Mitsubishi Electric (MELCO). This project proposes the replacement of the MEC5000 D-AVRs with the advanced MEC700 AVR System for Units 1 and 3, to mitigate obsolescence risks and ensure reliable operation;
- Covert Units 1 through 3 MTX High Voltage Bushing – GSU (\$1,015,200 total). The 1MTX GSU transformer has over 20 years of service life and its high voltage (HV) bushings are showing insulation deterioration that was exposed through power factor testing prior to Consumers Energy ownership. The GSU also is overdue for internal inspection with attention to mitigate risk for its pacified oil that is still exhibiting corrosive potential properties. To engineering's knowledge this unit has never been fully drained and undergone internal inspection prior to or after the oil pacification work was performed earlier in its life. The unit has oil that was pacified for corrosive Sulfur, however Doble and other industry experts strongly recommend the pacified oil be replaced as soon as possible since Sulfur corrosion leading to failure is still probable due to remaining residuals in the pacified oil. It was noted in the root cause analysis for the Zeeland Unit 2C GSU that corrosive sulfur had an impact on its failure by reacting with conductors to create localized overheating. The HV bushing replacement mitigates any potential for failure in service. The bushing insulation properties continue to degrade over time as indicated through recent power factor testing before Consumers Energy took over the site. HV bushings power factor test results give the impression the bushings of 1MTX should have 5-10 years of life remaining before failure is realized, however neither the rate of deterioration nor exact failure timeframe is predictable. Due to lead times, planning for replacement is a more cost-effective solution for customers than verifying they are failing during a future outage and forcing extension until they can be replaced. A major outage for Covert will be required to have enough time to execute the work, which will require at least 12 days based on similar scope at ZGS. Internal inspection is part of the preventative maintenance plan and helps the Company determine the health of the transformer, plan future outages as needed, and prevent forced outages, thereby reducing potential ROR;
- Units 1, 2, and 3 NERC Relay Replacements and Test Switch Installation (\$700,712). This project is needed to preclude unnecessary risk associated with

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possible relay failures as the existing relays are at the end of life. Running to failure is not an option for relay protection equipment because of the extremely high costs of equipment failures that could result if relay protection schemes failed to operate as designed. In late 2024, Covert experienced its first indication of a relay failure on Unit 3 and is operating at this time with no redundant protection in this specific zone. The failed relay is original to the plant and more relay failures can be expected as time goes on.

A failure of the remaining protection scheme in this zone would result in a forced outage, and it is expected that the turn-around time for sourcing, testing, installation, and commissioning of relays like this would take approximately two weeks if all went well. Relay manufacturers and Consumers Energy's High Voltage Distribution group use 25 years as recommended service life for these types of devices.

Each unit has multiple digital protection relays to ensure protection to the generation equipment (Generators/Exciters/Transformers) from local faults as well as to ensure protection from grid disturbances that could damage our valuable equipment. The original relays at Covert were not installed with the necessary test and cutout switches, which requires that the unit be offline for maintenance and replacement and creates greater potential for human performance errors that can jeopardize system reliability;

- LVDT Positioning Sensor – Units 1 and 3 Fuel Control Valves (\$507,000 each). The scope of these projects is to replace the Yokogawa 5516 mechanical type position sensors with LVDTs. The replacement to include the following devices, Main “A” pressure control fuel valve sensor, Main “B” pressure control fuel valve sensor, Main flow control fuel valve sensor, Pilot pressure control fuel valve sensor, and the pilot flow control fuel valve sensor and compressor bypass actuator. The benefits of this project include reduced maintenance, improved accuracy, and higher long-term reliability due to the removal of the mechanical linkages and converting to a non-contact mechanism.

The Covert Mitsubishi Power Gas turbines are equipped with Yokogawa 5516 mechanical linkage type position sensors. The Yokogawa position sensors are used to detect the position of the fuel control valves, bypass valve actuators, and the Inlet Guide Vanes. These Valves and their position are critical as they control turbine output which allows more load on the generator and meets load demand. The Yokogawa 5516 position sensors are obsolete, and Yokogawa has announced that the 5516 position sensors are no longer manufactured as of March 31, 2015, are no longer supported, and parts are no longer available. Mitsubishi Power recommends eliminating the Yokogawa mechanical linkage position sensors;

- Covert - HEPS/FAC/DAST Inspections (\$347,500). This project aims to bring the Covert site into compliance with existing corporate governance on

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1 G-A-313, G-A-314, and G-A-315 programs. Compliance with these programs
2 ensures the safe operation of the site and provides outage scheduling flexibility
3 by transitioning from a 12-month operating certificate to 2-year and 3-year
4 operating certificates. The project is essential to maintain the ability to
5 implement 2-year and 3-year operating certificates. Failure to perform the
6 required inspections would limit the unit to a 12-month operating certificate,
7 necessitating a full inspection before the unit can be certified to operate;

- 8 • Small Site Capital (\$285,000). This project supports capital expenditures for
9 replacement of small valves, instrumentation, tools, equipment, pumps, and
10 motors at Covert during the projected bridge period;
- 11 • Covert Base Outage Capital (\$360,000). Base outage capital covers the
12 replacement parts and issues found during turbine/generator inspections and the
13 major discovery issues found during annual unit outages; and
- 14 • Eighteen additional projects at Covert totaling \$2.185 million which support
15 safety, security, and reliability, with each project representing \$210,000 or less
16 in capital expenditures. These projects include Plant Fuel Gas Bypass System,
17 SP transformers, Gas Turbine - Unit 1 and 3 Evaporator Media, gas and steam
18 turbine excitation transformers, hydrogen new bulk system, Unit 2 LTSA extra
19 work, and air compressors.

20 **Karn Units 1 and 2**

21 **Q. Please explain the Company's projected capital investment for the 16-month**
22 **projected bridge period ending April 30, 2026 and the projected test year ending**
23 **April 30, 2027 for Karn Units 1 and 2.**

24 **A.** The Company does not plan to make any capital investments on Karn Units 1 and 2 in the
25 16-month projected bridge period ending April 30, 2026 or the projected test year ending
26 April 30, 2027, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 15,
27 columns (h) and (j), respectively, due to their retirement on May 31, 2023.

Karn Units 3 and 4

Q. Please explain the Company's projected capital investment for the 16-month projected bridge period ending April 30, 2026 and the projected test year ending April 30, 2027, for Karn Units 3 and 4.

A. The Company plans to invest \$12.478 million in the projected bridge period and \$8.304 million in the projected test year, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 22, columns (h) and (j), respectively.

Q. What is the basis for the projected \$12.478million capital investment in the 16-month projected bridge period?

A. The projected \$12.478 million capital investment will fund numerous safety, regulatory compliance, reliability, and infrastructure projects at Karn Units 3 and 4. There are four projects which are greater than \$1 million, and these projects are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 17 through 20.

The basis for these projects is described below:

- Karn Unit 3 Combustion Air Heater replacement (\$2,700,000). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Karn Units 3 and 4;
- Karn Unit 4 Combustion Air Heater replacement (\$3,000,000). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Karn Units 3 and 4;
- Karn Units 3 and 4 Ductwork Expansion Joint Replacement – Induction Draft (“ID”) Fans to Stack (\$1,800,000). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Karn Units 3 and 4;
- Karn Unit 4 Induced Draft (“ID”) Fan Inlet Damper Replacements (\$2,700,000). The scope of this project is to replace the ID fan inlet dampers. The Karn Unit 4 ID fan inlet dampers play a crucial role in regulating the fan load and maintaining a negative draft in the boiler, which is essential for safe and reliable operation. Over the last five years, the dampers have experienced multiple failures, leading to forced outages and significant de-rates, indicating

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1 the urgent need for replacement. The Karn Unit 4 ID Fan Inlet Damper
2 Replacement project is critical to ensuring reliable and efficient operation of the
3 unit. The current ID fan inlet dampers, which are essential for controlling the
4 boiler draft, are aging and have caused multiple forced outages and significant
5 capacity de-rates over the past five years. These failures have resulted in high
6 operational costs, inefficiencies, and risks of continued disruptions during peak
7 operational periods. Replacing the dampers is a proactive investment that will
8 eliminate these risks and provide long-term operational stability. The concept
9 approval document for this project is attached as Exhibit A-50 (RTB-11);

10 The following projects are less than \$1 million, but are important to reliability:

- 11 • Karn Unit 4 Vibration System Replacement (\$774,900). This project replaces
12 all Rockwell Automation XM Monitoring vibration modules that are currently
13 located in electrical junction boxes located around the Karn 4 turbine. The
14 existing junction boxes will be used as termination boxes and new cables run to
15 a central point on the Karn 4 turbine deck (turbine office at SW corner). A new
16 Ovation DCS cabinet with R-Line Machine Health Monitor “MHM” vibration
17 modules is to be installed in the turbine office area. This cabinet will contain
18 (6) 8-point MHM modules (total of 48 inputs) and two output
19 modules. Ovation OCC-100 redundant controllers will be used to integrate
20 with the existing Ovation DCS. The enclosure door will contain active buffered
21 output splitters to allow connection to the Consumers Energy turbine group’s
22 Turbo-Balancer. Redundant output modules will be utilized for proper
23 hardwired trip signals;

24 The existing Rockwell computer located in the Karn 3&4 DCS room will
25 be removed and all interfaces for the new system will be through the integrated
26 Ovation DCS operator and engineering drops. An Emerson Asset Management
27 System “AMS” Machine Works Server and Waveform Recorder Server
28 provides advanced condition monitoring and full vibration spectrum data for
29 historical playback of trip events and diagnostics of turbine issues. The sensors
30 and cables will also be replaced;

- 31 • BOP Capital tooling/valves/instrumentation (\$380,000). This project spans the
32 16-month bridge period and the test year, and its basis is included in my
33 discussion of the test year capital projects for Karn Units 3 and 4; and
- 34 • Ten additional projects at Karn Units 3 and 4 totaling \$1.123 million which
35 support safety, security, and reliability, with each project representing \$261,000
36 or less in capital expenditures. These projects include rewind of the Karn Unit 4
37 house service air compressor motor, replacement of the processors for the Karn
38 Units 3 and 4 main boiler feed pump relay control conversion to DCS, Karn
39 sync wire replacement, Karn Units 3 and 4 ID and forced draft (“FD”) fan
40 vibration systems, Karn Units 3 and 4 FD fan platforms, and replacement of
41 house service water (“HSW”) piping on Karn Units 3 and 4.

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1 **Q. What is the basis for the projected \$8.664 million capital investment in the projected**
2 **test year?**

3 A. The projected \$8.304 million capital investment in the projected test year will fund twelve
4 projects. Three of these projects are greater than \$1 million and are presented on Exhibit
5 A-12 (RTB-3), Schedule B-5.2, page 9, lines 15-17. The basis for these projects is
6 described below:

- 7 • Karn Units 3 & 4 Combustion Air Heater replacement (\$1,800,001 for Unit 3,
8 \$2,250,000 for Unit 4). The scope of these projects is to replace the combustion
9 air heaters. The D.E. Karn Generating Station, which utilizes natural gas and
10 oil, employs steam-to-air heat exchangers known as combustion air heaters to
11 preheat the ambient air entering the boiler. This preheating process is essential
12 for optimizing combustion efficiency. Specifically, Karn Units 3 and 4 rely
13 heavily on consistent air intake temperature to fine-tune the combustion air-fuel
14 mixture, crucial for maintaining emissions within acceptable opacity limits and
15 ensuring efficient heat rates as they do not have any other means of controlling
16 the output of particulate matter. The projected benefits include enhanced
17 reliability, improved efficiency, and ensured regulatory compliance, avoiding
18 projected capacity revenue losses of over \$23 million. This proactive approach
19 addresses the root cause of failures, providing a long-term solution for
20 operational efficiency and cost savings. The concept approval document for
21 these projects is attached as Exhibit A-51 (RTB-12); and
- 22 • Ductwork Expansion Joint Replacement –ID Fans to Stack (\$1,800,000). This
23 project will replace all expansion joints and entry doors between the ID Fans
24 and the stack. All expansion joints between the ID Fans and the Stack are
25 beyond their end of life and suspected to be severely degraded based upon the
26 condition of expansion joints found during the Karn Unit 3 Breeching project.
27 Failed expansion joints will need to be replaced to maintain environmental
28 compliance. This scope of work will make the ductwork air-tight again to
29 maintain environmental compliance.

30 The following projects are less than \$1 million, but are important to reliability:

- 31 • Karn Unit 3 Residual Oil Heater Overhaul (\$495,000). The scope of this project
32 is to install new tube bundles. The existing tube bundles have many leaks, and
33 the heaters are no longer functioning and are cut out of the system;
- 34 • Karn Unit 4 Ductwork Replace Insulation & Lagging - Boiler to Stack
35 (\$750,000). The scope of this project is to replace the lagging and insulation on
36 all the ductwork from the building out to the stack. The existing lagging and
37 insulation needs to be removed, the underlying steel fixed as necessary, and

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new insulation and lagging installed. The steel structure that the ductwork lagging is attached to is severely corroded. This has allowed multiple random failures of the lagging, resulting in a safety concern due to pieces of lagging falling to the ground or becoming airborne during wind events;

- Karn Units 3 and 4 ID and forced draft (“FD”) Fan Vibration Systems (\$266,400 per unit). The existing ID Fan Vibration System was originally used for monitoring and alarming purposes only and was not designed to be a vibration protection system. When a catastrophic ID Fan failure occurred in 2016, the vibration alarms were changed from only alarms to also tripping the fan. With this change, the Company had several false positive trips from the system resulting in unit trips. The original system currently provides an analog signal into the DCS where the values are displayed and alarm messages are generated, and the DCS stops the ID fan if the analog value goes above the trip limit.

This project replaces the current system with Ovation Machinery Health Monitor R-Line modules located in an Ovation remote I/O cabinet near the ID Fans. The remote drop will utilize Ovation Remote Node Interface for connection into the existing Ovation DCS. This will also provide vibration monitoring and protection for the FD Fans. A total of 24 speed and vibration sensors are included for the two ID and two FD fans and motors (3A and 3B ID Fan and motor, and 3A and 3B FD Fan and motor). Active buffered output splitters at the enclosure are also included to allow for supported vibration monitoring with a 2140 portable monitor and use of the turbo balancer for fan balancing. All waterfall and waveform plots of the vibrations are available for display on the Ovation system. Full API-670 protection capability is provided with seamless integration to the existing Emerson Ovation DCS;

- Capital tooling/valves/instrumentation (\$285,000). This project supports capital expenditures for replacement of small valves, instrumentation, tools, equipment, pumps, and motors at Karn Units 3 and 4 during the projected test year; and

Three additional projects at Karn Units 3 and 4 totaling \$0.392 million which support reliability, with each project representing \$180,001 or less in capital expenditures. These projects include the Karn Units 3 and 4 FD fan outlet dampers, HSW piping replacement, and tank farm PLC/DCS replacement.

Zeeland Plant

Q. Please explain the Company's projected investment for the 16-month projected bridge period ending April 30, 2026 and projected test year ending April 30, 2027 for the Zeeland Plant.

A. The Company plans to invest \$67.275 million in the 16-month projected bridge period and \$40.023 million in the projected test year at the Zeeland Plant, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 29, columns (h) and (j), respectively. These capital expenditures will be facilitated, in part, by 35-day outages on Zeeland Units 1 and 2 in the spring 2025 as well as short outages of about 15 days in the spring and fall of the 16-month projected bridge period and the projected test year. The Company has an LTSA with GE that covers many reliability investments at the Zeeland Plant.

Q. What is the basis for the projected \$67.275 million capital investment in the 16-month projected bridge period?

A. The projected \$67.275 million capital investment will fund numerous safety, regulatory compliance, reliability, and infrastructure projects at the Zeeland Plant. There are five projects which are greater than \$1 million, and these projects are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 12 through 16. The basis for these projects is described below:

- LTSA/Phase I Gas Turbine Advanced gas path replacement and axial fuel staging (\$43,697,329). This project spans the projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Zeeland Plant;
- Zeeland Phase II Turbine Replacements (\$10,174,501). This project spans the projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Zeeland Plant;
- Zeeland Purchase of Site Spare GSU transformer (\$2,340,637). This project spans the projected bridge period and the projected test year, and its basis is

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included in my discussion of projected test year capital projects for the Zeeland Plant;

- Unit 5 GSU Transformer Rewind (\$2,430,000). The scope of this project was to remove the failed Zeeland Unit 5 GSU transformer, movement and installation of the spare GSU transformer, and send out the failed Zeeland Unit 5 GSU transformer for overhaul which included milestone payments for the overhaul. In addition, the scope reflected the monthly lease of a spare transformer to provide continued operation of the unit for customers. Zeeland Unit 5 was taken out of service on December 17, 2022 and was returned to service on January 23, 2023 upon installation of the leased transformer which was moved from Zeeland Unit 1. The project cost for 2025 reflects the return of the leased transformer as well as the remaining lease payment; and
- Zeeland Plant LTSA supplementals not included in contract (\$4,703,401). This project spans the projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Zeeland Plant.

The following projects are less than \$1 million but are important to regulatory compliance and reliability:

- GasTurbine inlet filters replacement (\$360,000). The scope of this project is to replace canister filters. The filters are required to be replaced every five years and must be accomplished during an outage. The purpose of the project is to maintain the integrity of the filters to prevent material ingress to the turbines;
- Small Site Capital (\$380,000). This project spans the projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Zeeland Plant;
- Asea Brown Boveri (“ABB”) DCS Evergreen (\$648,680). This project upgrades the ZGS BOP DCS with the latest version available at the time of the project. The system is currently running on a VMware virtualized system. The system was installed in 2020. This Evergreen will only replace the existing ABB Software, Operating Systems, and miscellaneous upgrades. The controller drops and rack-mounted servers will not be replaced for this upgrade;
- ZGS – General Electric DCS Evergreen (\$839,665). The scope of this project is to upgrade the Zeeland Plant Turbine Controls DCS with the latest version available at the time of the project. The system is currently running on a VMware virtualized system which was installed in 2020. This Evergreen will only replace the existing GE Software, Operating Systems, and miscellaneous upgrades. This project will allow the latest versions of control software and operating systems to be used for reliable operation and control of the generating units. The latest feature enhancements are also available for operation. This will also allow the latest patches to be applied by the cyber security Emerson PWCS application.

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The DCS must be upgraded at a four-to-five-year upgrade cycle to maintain reliable control and recent operating systems and applications that are patchable. The vendor life cycle for DCS versions is generally five years. After five years they enter a retired state and are no longer patched. Microsoft Operating Systems are on a limited life basis, and they reach the end of “extended support” and no longer get security patches;

- Min Flow Bypass Valves Replacement (\$450,000). The scope of this project is to replace four minimum flow bypass valves. These valves are original to the plant and recent inspections have indicated nearly all the valve internals need replacement, which is also evident during operation with excessive leak-by. It was determined the most sensible approach is replacement due to the extent and cost of recommended repairs, and new valves will ensure continued reliability for 10+ years in the control of minimum flow for the FW pump system;
- Cooling Tower Transformer Replacement (\$225,000). The scope of this project is the replacement of the cooling tower transformer. Recent electrical testing indicated the transformer is failing. The Company determined that the most prudent option was replacement as compared to major repairs on a small transformer. Without this transformer, the cooling tower fans would not be operable, resulting in the Zeeland Phase 2 Units being shut down;
- Zeeland Plant Base Outage Capital (\$381,900). This project spans the projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Zeeland Plant; and
- Seven additional projects at the Zeeland Plant totaling \$0.644 million supporting safety, reliability, regulatory compliance, infrastructure, and operations, with each project representing less than \$180,000 or less in expenditures. These projects include Phase II 2A and 2B battery monitoring system, GT1B excitation transformer failing components, and peaking plant Generation Peaker.

Q. What is the basis for the projected \$40.023 million capital investment in the projected test year?

A. The projected \$40.023 million capital investment in the projected test year will fund numerous safety, regulatory compliance, reliability, and infrastructure projects at the Zeeland Plant. There are four projects which are greater than \$1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 11-14. The basis for these projects is described below:

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- Zeeland Site Spare GSU Transformer (\$4,481,207). The scope of this project is the procurement of a spare GSU transformer for the Zeeland site. The Zeeland Plant consists of four gas turbine powered plants and one steam turbine powered plant. The units transmit their power to the grid via GSU transformers. If a GSU were to fail, then the associated turbine would not be able to transmit power and would not be able to generate energy and capacity market value for Consumers Energy and its customers. For the Zeeland combined cycle plant, the combustion turbine requires the operation of the steam turbine, therefore the loss of the steam turbine's GSU transformer would effectively limit operation of two connected combustion turbine units. The lead time for a GSU transformer is currently three to four years and spare units at other facilities are not viable replacements due to compatibility and installation challenges. This project would purchase a spare GSU transformer that is sized to be able to replace any of the existing transformers on site and develop redundancy for any minor power upgrades in the future;
- Phase II GT Advanced gas path replacement and axial fuel staging (\$13,923,002). Zeeland Generating Station is a gas-powered combustion turbine plant consisting of four gas turbines and one steam turbine. These turbines are covered by a LTSA with General Electric to provide overhauls and upkeep on the units to periodically restore them to like-new condition. Periodically, the units are shut down for a major outage that is performed by General Electric. Part of the major work executed during such outages is replacement of the "hot", or combustion, parts as they degrade over their 32,000-hour design life. During these outages is the ideal time to incorporate major work that will improve the performance and/or reliability of the unit. The two gas turbines at Zeeland Phase 2 have Major Inspection outages in 2028. This project is to implement upgraded replacement parts in both phase 2 gas turbines. One such performance improvement (while maintaining the same reliability) is called an Advanced Gas Path ("AGP"). The AGP package provides significant output and efficiency (heat rate) improvements by replacing the turbine and combustion parts with higher performing and more technologically advanced parts. An additional improvement (while maintaining the same reliability) is called Axial Fuel Staging ("AFS"). The AFS package enables significant output turndown capability by replacing and adding combustion hardware with more technologically advanced parts that enable lower load operation while maintaining emissions compliance. This technology is potentially key to the Zeeland Phase 2 plant's ability to be flexible in supporting Consumers Energy's new energy portfolio, where a dramatic increase in renewable energy will demand greater flexibility from the rest of the generating assets in the portfolio. A more detailed analysis of this project is presented in Exhibit A-44 (RTB-5);
- Zeeland Plant LTSA/Phase I Gas Turbine Advanced gas path replacement and axial fuel staging (\$8,331,428). This is the capital portion for negotiated services that cover the planned normal maintenance of each unit based on its equivalent operating factor fired hours. The planned maintenance includes the

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1 following support services (OEM on-site/off-site technical support, engineering,
2 and labor). Typical activities include borescope inspections, capital repairs,
3 unit tuning, addressing service bulletin requirements, and on-site inspections.
4 Based on the OEM's operating and historical experience, if the Company
5 executes the normal planned maintenance and inspections according to the
6 recommended schedules, the Company will mitigate unexpected premature
7 failures of the equipment. Normal maintenance will ensure the Company
8 continues reliable operation of the units.

9 The Phase I Gas Turbine Advanced gas path replacement and axial fuel
10 staging project is being implemented in the Company's spring Phase 1 outage
11 beginning on April 21, 2025. A more detailed analysis of this project is
12 presented in Exhibit A-44 (RTB-5): Zeeland Phase 1 Gas Turbine upgrades;

- 13 • Phase II Turbine Replacements (\$10,174,501). The scope of this project
14 replaces the existing rotor with a new rotor, giving another 144,000 hours of
15 operation which would enable operation until the next rotor replacement out to
16 approximately the year 2045. Also included in this scope are new compressor
17 stator vanes due to the compressor being 20 years old; the best way to restore
18 the compressor to like-new condition is to replace the stationaries when the
19 blades will already be replaced. Lastly, the exhaust frame will be upgraded to
20 a robust exhaust frame due to reliability issues over the years, and the rotor
21 replacement being an appropriate time to replace the exhaust frame.

22 Several other critical projects which are less than \$1 million but are important to reliability
23 and infrastructure include:

- 24 • Zeeland Plant LTSA supplementals not included in contract (\$810,000). The
25 LTSA supplemental work is defined as the work that is not covered under
26 normal planned maintenance in the LTSA. Based on historical outage
27 experience there are typical discovery items found on this style of gas turbines
28 that are not part of the LTSA planned maintenance scope. Some of the typical
29 items that need to be addressed are labor and material to replace the following:
30 blading, combustion cans, ignitors, vanes/bushings, and any components on the
31 compressor end as the compressor is not covered under the LTSA;
- 32 • Small Site Capital (\$285,000). This project supports capital expenditures for
33 the replacement of small valves, instrumentation, tools, equipment, pumps, and
34 motors at Zeeland during the projected test year;
- 35 • Zeeland Plant Base Outage Capital (\$382,500). Base outage capital covers the
36 replacement parts and issues found during turbine/generator inspections and the
37 major discovery issues found during annual unit outages at Zeeland;
- 38 • Combined Cycle Units 3 and 4 Air Filter Replacement (\$648,000). The scope
39 of this project is to replace canister filters. The filters are required to be replaced

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every five years and must be accomplished during an outage. The purpose of the project is to maintain the integrity of the filters to prevent material ingress to the turbines; and

- Ten additional projects at the Zeeland Plant totaling \$0.987 million support reliability and operations, with each project representing \$240,000 or less in expenditures. These projects include Unit 1 and 2 battery monitoring system, 177, 277, 500 345kV breaker replacement, Phase 2 feed pump hydraulic coupling replacement, and Phase 1 Bentley Nevada vibration monitoring unit replacement.

Jackson Plant

Q. Please explain the Company's projected investment for the 16-month bridge period ending April 30, 2026 and test year ending April 30, 2027 for the Jackson Plant.

A. The Company plans to invest \$24.489 million in the 16-month projected bridge period and \$28.143 million in the projected test year at the Jackson Plant, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 36, columns (h) and (j), respectively. This will be facilitated by short outages in the spring and fall of 2025 and 2026. The Company has an LTSA with General Electric to cover many reliability issues at the Jackson Plant.

Q. What is the basis for the projected \$24.489 million capital investment in the 16-month projected bridge period?

A. The projected \$24.489 million capital investment in the 16-month projected bridge period will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are four projects which are greater than \$1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 8-11. The basis for these projects is described below:

- Jackson Plant LTSA (\$16,200,153). This project spans the 16-month projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Jackson Plant;
- Jackson Plant LTSA Extra Work (\$2,115,001). This project spans the 16-month projected bridge period and the projected test year, and its basis is

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1 included in my discussion of projected test year capital projects for the Jackson
2 Plant;

- 3 • GSU Transformer Site Spare (\$1,333,333). This project spans the 16-month
4 projected bridge period and the projected test year, and its basis is included in
5 my discussion of projected test year capital projects for the Jackson Plant; and
- 6 • LM6000 ESN 191-306 HP Turbine S2 Nozzle replacement (\$1,336,072).
7 During the bi-annual borescope inspection in April 2024 for the LM6000 gas
8 turbines at Jackson Generating Station, damage was identified at the High-
9 Pressure Turbine (“HPT”) Stage 2 Nozzle (“S2N”) Impingement Ring of
10 Engine Serial Number (“ESN”) 191-306. The gas turbine with ESN 191-306
11 was placed in an 'on watch' period per OEM guidance that results in a 250
12 running hour inspection frequency to determine if the damage progresses. There
13 is potential for the inspection frequency period to increase based on multiple
14 inspections. Ultimately the S2N assembly of the gas turbine that is damaged
15 needs to be replaced to restore the gas turbine to a serviceable condition.

16 Several other critical projects which are less than \$1 million but are important to reliability
17 and infrastructure include:

- 18 • JLM1-6 Variable Inlet Guide Vane (“VIGV”) Project (\$646,911). This project
19 spans the 16-month projected bridge period and the projected test year, and its
20 basis is included in my discussion of projected test year capital projects for the
21 Jackson Plant;
- 22 • Jackson Generating Station General Electric DCS Replacement (\$720,000).
23 This project replaces the GE DCS with the latest version available at the time
24 of the project. The system is currently running on a VMware virtualized
25 system. The system was installed in 2020. This Evergreen will only replace
26 the existing GE Software, Operating Systems, and miscellaneous upgrades.
27 The controller drops and rack-mounted servers will not be replaced for this
28 upgrade. (Standard practice is to replace virtualized system hardware every
29 eight years to reduce costs.) The DCS must be upgraded at a four-to-five-year
30 upgrade cycle to maintain reliable control and recent operating systems and
31 applications that are patchable. Vendor life cycle for DCS versions is generally
32 a five-year cycle. After five years they enter a retired state and are no longer
33 patched. Microsoft Operating Systems (O/S) are on a limited life basis, and they
34 reach the end of “extended support” and no longer get security patches.
35 Corporate policies require all systems to be patched regularly along with Anti-
36 Virus updates;
- 37 • LM6000 ESN 191-345 HP Turbine S1 Blade Replacement (\$763,781). There
38 are three LM6000 gas turbines (“GTs”) at JGS that are currently experiencing
39 burn through on their HPT Stage 1 Blades (“S1B”). Burn through represents
40 the loss of a protective thermal barrier coating on the blades and the beginning

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of wear into the blade surface and base metal. Once any individual blade of the HPT S1B set meets an unserviceable condition per the OEM specifications, the gas turbine will not be allowed to operate. The three LM6000 GTs that are experiencing this condition are indicated by their ESN, ESN 191-339, ESN 191-345, and ESN 191-307. There are bi-annual borescope inspections (“BSI”) of all the JGS LM6000 GTs that monitor the GT condition. The BSI is the time where the HPT S1B condition is determined to be serviceable or unserviceable.

The three GTs of concern at this time are in a similar state of condition, but the timing and the sequence of an unserviceable condition for each will be based on the BSI. In general, the first GT in sequence that is labeled unserviceable will be pulled from service, sent for repair with a new set of HPT S1Bs, and returned to JGS. The set of HPT S1Bs pulled from the first GT will be overhauled and made available for the second GT that becomes unserviceable, and the set of HPT S1Bs pulled from the second GT will be overhauled and made available for the third GT that becomes unserviceable. The set of HPT S1Bs pulled from the third GT will be overhauled and returned to JGS to be used for future needs;

- Small Site Capital (\$380,000). This project spans the projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Jackson Plant;
- Base Outage Capital (\$270,000). This project spans the 16-month projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Jackson Plant; and
- Nine additional projects at the Jackson Plant totaling \$0.724 million, with each individual project representing \$225,000 or less in expenditures. These projects include Major Motor and Pump Replacements, Outdoor and roadway LED lighting replacement, Engine 191-306 Overhaul, Unit 7 Gas turbine rotor replacement, and LM6000 Beckwith Relay Replacement.

Q. What is the basis for the projected \$28.143 million capital investment in the projected test year?

A. The projected \$28.143 million capital investment in the projected test year will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are four projects which are greater than \$1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 7-10. The basis for these projects are described below:

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- Jackson Plant LTSA (\$12,810,121). This is the capital portion for negotiated services that cover the planned normal maintenance of each unit based on its equivalent operating factor fired hours. The planned maintenance includes the following support services: OEM on-site/off-site technical support, engineering, and labor. Typical activities include borescope inspections, capital repairs, unit tuning, addressing service bulletin requirements, and on-site inspections. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected pre-mature failures of the equipment. This will help maximize availability and, as a result, optimize customer value for the site. Normal maintenance will ensure the Company continues reliable operation of the units;

- Engine 191-306 Overhaul (\$6,130,000). The project involves the provision of a nozzle assembly from General Electric. General Electric will also provide three field service representatives to remove the gas turbine from its package, replace the HP Turbine Rotor assembly, reassemble the gas turbine, install it back in the package, perform alignment, and provide startup support. The work will take place at the Jackson facility.

During the bi-annual borescope inspection in April 2024 for the LM6000 gas turbines at Jackson Generating Station, damage was identified at the HPT S2N Impingement Ring of ESN 191-306. The gas turbine with ESN 191-306 was placed in an 'on watch' period per OEM guidance, resulting in a 250 running-hour inspection frequency to monitor the damage progression. Ultimately, the S2N assembly of the gas turbine needs to be replaced to restore the gas turbine to a serviceable condition;

- Unit 7 gas turbine rotor replacement (\$1,663,577). The scope of this project is to replace the Unit 7 Gas Turbine Rotor as it is essential to prevent high-probability failures, ensure continued operation, and avoid significant downtime. This investment will provide long-term reliability and efficiency for the plant's operations, ensuring optimal performance of the gas turbine. The Jackson Generating Station Unit 7 Gas Turbine Rotor Replacement project is a critical initiative aimed at ensuring the continued operation and efficiency of the GE 7EA gas turbine. The rotor for this turbine has a life limit of either 5,000 starts or 250,000 running hours. A new rotor will take approximately two years to be delivered after the order; and

- GSU Transformer Site Spare (\$2,333,334). This project provides Jackson with a reliable spare GSU to which it currently does not have access. The main transformers (GSUs) are a single point of failure in delivering power from the generators to the grid. For failure of one main transformer, lost generation would be 47 MW to 104 MW, depending on which generator(s) are connected. The lead time for a new transformer is three-to-four years, since every transformer of this size is custom built, and a large quantity of special raw materials is required. The Company's spare transformers located at Campbell,

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Karn, Lake winds, and Crosswinds do not have the correct voltage (138kV-13.2kV-13.2kV) or correct winding configuration (WYE-DELTA) to function at Jackson so they cannot be considered for use as spares. The concept approval for this project is presented in Exhibit A-45 (RTB-6).

Several other critical projects which are less than \$1 million but are important to reliability and infrastructure include:

- JLM1-6 VIGV Project (\$960,102). This project will install new VIGV systems on six LM6000PC engines at the Jackson Plant. The seventh LM6000PC engine has a partial installation already, and the project will complete the VIGV system for this engine. For LM6000PC SPRINT gas turbines, which the Jackson Plant has, the VIGV upgrade is expected to yield a significant fuel efficiency improvement at part power. The average fuel efficiency improvement at 70% of maximum power is greater than 2%. The VIGV also helps minimize variable bypass valve ("VBV") flow and pressure levels, thereby reducing associated flow noise. The VIGV system improves performance for both simple cycle and heat-recovery cycles when operating at less than full load;
- Jackson Plant LTSA Supplemental Work (\$315,000). The LTSA supplemental work is defined as the work that is not covered under normal planned maintenance in the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items that need to be addressed are labor and material to replace the following: blading, combustion cans, ignitors, vanes/bushings, and any components on the compressor end as the compressor is not covered under the LTSA;
- Base Outage Capital (\$270,000). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages;
- 735 Breaker relay replacement (\$384,300). One of the General Electric Multilin 735 relays that provides overcurrent protection to a large motor failed in service. This model of relay is no longer available. There are five of these relays at the Jackson plant. When another one fails, the motor will be forced out of service for a long duration while relays of a different manufacturer are installed. System protection recommends install of a SEL-551C and a BE1-851 as replacement;
- Steam turbine 9 blade replacement (\$260,837). Impact damage was identified during the last major inspection of the unit in 2018. The first stage nozzle of the Jackson Generating Station had a design flaw failure where the peened caulking strips that hold the nozzle in its axial position liberated themselves from their original positions in the caulk/peen groove because of the expansion and

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contraction in the area. The liberation of these pieces caused impact damage to downstream components, most notably the rotor's blading. General Electric recommended at that time that repairs be made during the next major inspection. Blade replacement is needed for stages 1, 2, and 12. Other stages' blading may require similar repairs. The rotor needs machining at radius leading to the stage 1 buckets due to imperfections from previous impact damage. Stage 10 blade covers need to be removed and replaced with "Foxhole" type covers due to impact damage and erosion. The likelihood of the issues noted above achieving further degradation is high. The severity of consequence of leaving the above-mentioned damage as-is is high. The overall risk assessment is high (> 50%). For the longevity of the unit these items need to be addressed during the upcoming, routine overhaul;

- LM6000 ESN 191-307 HP Turbine S1 Blade Replacement (\$782,866). There are three LM6000 GTs at JGS that are currently experiencing burn through on their HPT S1B. Burn through represents the loss of a protective thermal barrier coating on the blades and the beginning of wear into the blade surface and base metal. Once any individual blade of the HPT S1B set meets an unserviceable condition per the OEM specifications, the gas turbine will not be allowed to operate. The three LM6000 GT's that are experiencing this condition are indicated by their ESN, ESN 191-339, ESN 191-345, and ESN 191-307. There are bi-annual BSI of all the JGS LM6000 GT's that monitor the GT condition. The BSI is the time where the HPT S1B condition is determined to be serviceable or unserviceable.

The three GTs of concern at this time are in a similar state of condition, but the timing and the sequence of an unserviceable condition for each will be based on the BSI. In general, the first GT in sequence that is labeled unserviceable will be pulled from service, sent for repair with a new set of HPT S1B's, and returned to JGS. The set of HPT S1B's pulled from the first GT will be overhauled and made available for the second GT that becomes unserviceable, and the set of HPT S1B's pulled from the second GT will be overhauled and made available for the third GT that becomes unserviceable. The set of HPT S1B's pulled from the third GT will be overhauled and returned to JGS to be used for future needs;

- LM6000 HP Turbine S1 Blade Overhaul (\$817,859). There are three of six LM6000 GT at JGS that are experiencing deterioration of their HPT S1B from normal operation. The HPT S1Bs are experiencing burn through which is described as the loss of the protective thermal barrier coating on the blades and the beginning of wear into the blade surface and base metal. Once any individual blade of the HPT S1B set meets an unserviceable condition per the OEM specifications, the gas turbine will not be allowed to operate. The three LM6000 GTs of concern will go through a sequence of replacing the HPT S1B, once the third GT is complete there will be a set of HPT S1B that will need to be overhauled for availability to the next LM6000 GT that requires the same

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blade set. This project is to capture the cost of the blade overhaul following the third LM6000 GT HPT S1B replacement;

- Small Site Capital (\$285,000). This project supports capital expenditures for the replacement of small valves, instrumentation, tools, equipment, pumps, and motors at Zeeland during the projected test year; and
- Ten additional projects at Jackson Plant totaling \$1.130 million, with each individual project representing \$225,000 or less in expenditures. These projects include 269 Breaker relay replacement, Site Control Room heating, ventilation, and cooling (“HVAC”) Replacement, 4160V Electrical Room HVAC Replacement, steam turbine 8&9 turning gear platforms, and Major Motor and Pump Replacement.

HYDRO UNITS

Q. Please explain the Company’s projected capital expenditures for the 16-month projected bridge period ending April 30, 2026 and the projected test year ending April 30, 2027 for the Hydro Units.

A. The Company is not presenting any capital investments during the 16-month bridge period or projected test year in the Hydro Units, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 3, line 50, columns (h) and (j), respectively. The Company is requesting continued deferral treatment as discussed in more detail in the direct testimony of Company witness Myers.

LPS

Q. Please explain the Company’s projected capital expenditures for the 16-month projected bridge period ending April 30, 2026 and the projected test year ending April 30, 2027 for the LPS.

A. The Company plans to invest \$15.225 million in the 16-month projected bridge period and \$13.282 million in the projected test year in the LPS, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 3, line 57, columns (h) and (j), respectively. These capital investments will be implemented during periodic outages in 2025 through 2027. It is

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important to note that none of these investments are associated with resolving the Toshiba defects. Those investments are being recorded to a regulatory asset pursuant to the MPSC's May 18, 2023 Order in Case No. U-21310.

Q. What is the basis for the projected \$15.225 million capital investment in the 16-month projected bridge period?

A. The projected \$15.225 million capital investment in the 16-month projected bridge period will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are six projects which are greater than \$1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 21-26. The basis for those projects is described below:

- Ludington Units 1 through 6 DCS Control Relay Replacement (\$2,971,797). This project spans the 16-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;
- LPS – Lower Penstock Expansion Joint (“LPEJ”) Chamber Waterstop replacement (\$2,009,804). The scope of this project is the replacement of the LPEJ waterstop and potentially dewatering the surrounding groundwater. The engineering study was performed in 2020 at a cost of \$0.404 million and project implementation began in 2021 and is planned to be completed in May 2025. In 2021, the engineering was completed, and the design was approved by FERC; and

The LPEJ Chambers enclose the penstock expansion joints in concrete chambers. The penstock expansion joints allow penstock expansion with seasonal temperature changes. The waterstop is a membrane intended to prevent groundwater from leaking into the LPEJ. Some joints have been leaking since shortly following plant construction. In February 2017, a depression was discovered upstream of Ludington Unit 3, which was caused by transport of soil into the chamber by inflowing groundwater. Historically, Consumers Energy sealed the leaks into the LPEJs using hydrophobic polyurethane grout. However, the waterstops are at the end of their expected life and grouting is no longer an effective solution. Failure to remedy the in leakage is a threat to generation because if the settlement of the chambers reaches a certain threshold, the generation unit(s) will remain in a forced outage until the LPEJ chamber(s) can be stabilized. The implementation of this project

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reduces current risk of a potential failure mode and supports Ludington unit generation well into the relicensing period;

- Ludington 1 Pony Motor Overhaul (\$2,266,667). This project spans the 16-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;
- Replace 480V Dike Load Center (“DLCs”) (\$1,287,697). This project spans the 16-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;
- Governor Replacement (\$2,026,247). This project spans the 16-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington; and
- Station Water Discharge Isolation Valve (\$1,161,403). The scope of work will consist of the installation of a separate, parallel train oil water separator (“OWS”) to that of the plant’s existing modification of existing support systems (station sump, station sump pumps, & metering devices) to support new OWS, and retrofit of existing OWS to improve oil separability. This will allow temporary use of the modified original OWS while servicing the anticipated new one so as to not impact unit availability. The Station Water Discharge Header Isolation Valve and Oil Separator was previously approved into the LTFP to assess the stations OWS due to off process conditions that had resulted in reportable releases of oil into Lake Michigan. The main goal of this project was to perform formal engineering evaluation of the plant’s existing OWS to identify if it could likely serve the facility through the current relicensing period (2069) without major modification or replacement. In the intervening time since that project was initiated, however, two separate reportable oil releases (as of March 8, 2022) have occurred (Dec 2021 & Jan 2022). During evaluation of these events, prior documentation & engineering analysis (1140-319-001 OIL WATER SEPARATOR) of the existing OWS was located that indicates it has suffered numerous failures in the past and is not effective at removing contaminants from the influent to satisfy the facilities mandated NPDES effluent requirements. As stipulated by the project charter, “Should the above engineering evaluation conclude that significant changes are needed to the separator or system configuration to meet current environmental and regulatory standards a new project and LTFP funding request will be initiated to implement these changes and utilize the engineering design basis established within this project.” With the discovery of the aforementioned documentation pertaining to the plant’s current OWS (1140-319-001), the justified conclusion is that significant modifications to the system will be necessary to meet current and future environmental standards. Therefore, this project will establish the funding request to implement those changes to the facility and utilize the

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1 previously approved project to provide detailed engineering for such
2 modification.

3 The following projects are less than \$1 million but are important to regulatory compliance
4 and reliability:

- 5 • Station Power Transformer Life Cycle Management (\$442,156). This project
6 spans the 16-month projected bridge period and the projected test year, and its
7 basis is included in my discussion of the projected test year capital projects for
8 Ludington;
- 9 • Replace Barrier Net Panels (\$400,010). This project spans the 16-month
10 projected bridge period and the projected test year, and its basis is included in
11 my discussion of the projected test year capital projects for Ludington;
- 12 • LPS Intake Gate and Gate House Mechanical Replacement (\$425,376). This
13 project spans the 16-month projected bridge period and the projected test year,
14 and its basis is included in my discussion of the projected test year capital
15 projects for Ludington;
- 16 • Centralized Grease System Replacement (\$303,300). The current electro-
17 pneumatic grease system(s) that service the wicket gate bushings are
18 functioning past their service life and are of questionable reliability (original
19 plant equipment). Most of the components have worn seals, leak grease, and
20 have basic function. Replacement of end of service life components such as
21 pumps, distributing blocks, and solenoid valves. This project will modernize
22 the existing control system to a self-diagnostic PLC system;
- 23 • Ludington All Unit Critical Valve and Actuator Replacement (\$487,713). The
24 scope of this project is to replace valves, actuators, and associated equipment
25 critical to unit specific operation. There are also certain valves that provide
26 routine tagging points that provide worker protection. Many of these valves
27 have known issues such as damaged seals (leakage when the valve is closed),
28 leaking packing (cannot be tightened further), and severely corroded valve stem
29 extensions. Additionally, many of these valves are paired with pneumatic
30 actuators which have also been identified with operational issues. Most of the
31 handwheels are broken and do not provide a secondary means of operating the
32 valve if the pneumatic actuator were to fail. This could present a particularly
33 dangerous situation if a pipe were to fail. Additionally, damage to the actuator
34 linkages and slides have been noted in previous inspections. The linkage
35 damage has introduced play or slop into the mechanism which can be seen
36 during operation and will lead to eventual failure of the mechanism; and
- 37 • Fifteen additional projects at LPS totaling \$1.443 million, with each individual
38 project representing \$240,522 or less in expenditures. These projects include
39 Guide Bearing Oil Float Replacement, all unit flow transmitter replacement,

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ABB/Governor air compressors, Inlet 17 outlet corrugated pipe replacement, oil processing equipment replacement, and small tools, pumps, motors, valves, and instrumentation.

Q. What is the basis for the projected \$13.282 million capital investment in the projected test year?

A. The projected \$13.282 million capital investment in the projected test year will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are four projects which are greater than \$1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 18 through 21. The basis for these projects is described below:

- DCS Control Relay Replacement (\$2,906,676). The scope of this project is to replace and eliminate worn and less reliable control relays with new electronic I/O modules and new relays where needed. The number of hardware control relays will be reduced due to the “control” being performed in logic instead of “hardwired” circuits. This will increase reliability and reduce outages and unit derates. Common control and monitoring of system equipment allows operation of the equipment from the HMI graphics and keeps the operator focused on one system instead of monitoring several systems from several areas of the control room.

The LPS units are controlled by using the original hardwired electromechanical relay control system to operate the units. A modern DCS system will provide the LPS units with improved diagnostic and troubleshooting capabilities. The DCS system will make it easier to automate any updates of equipment and systems that are integrated with the unit operation, and to implement, test, and verify changes to operating criteria. Furthermore, the modern DCS has the capability to perform these functions at a lower cost and requiring less time.

The existing relay control system is based on electromechanical devices that wear and become less reliable over time. The relay contacts wear, and increased resistance can cause intermittent failures. Troubleshooting these issues are difficult and time-consuming. The relay control system will not last until end-of-life of the units and need to be upgraded to a modern DCS control system. The Emerson Ovation DCS infrastructure was installed as part of the 2019-2021 Data Acquisition System (“DAS”), Annunciator, PLC, and Sequence of Events recorder replacement project. This provides a common historian, HMI graphics control, alarm management system and modern control system for reliable

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efficient unit operation. The DAS project provides the infrastructure to build upon for full site/unit control at LPS;

- Ludington 1 Pony Motor Overhaul (\$2,800,000). The project will remove and replace the existing pony motor rotors with new rotors that will provide another 50 years of service. It is assumed that the stators on both units can be reused, and that the new rotor will be designed to work with the existing stator and liquid rheostat. The new rotor will be redesigned to ensure that fatigue is no longer an issue for the remaining life of the plant.

During the overhaul of Unit 1 (performed by Toshiba in 2018 and 2019), a Non-Destructive Examination (“NDE”) test performed on the pony motor rotor structure recorded linear indications, a.k.a. cracks, in presumed high stress locations. Consumers Energy requested analysis by Toshiba at that time to confirm the stress state of the rotor in operation, but Toshiba did not complete it (note that while the Company requested this analysis from Toshiba, pony motor replacement was not part of Toshiba’s scope for the overhaul). Prior to re-assembly after the major overhaul work, the linear indications had been repaired by Toshiba. The unit experienced problems with fastener failures after being returned to service, and subsequent inspections identified that the linear indications (cracks) returned, and that the indications continued to grow in volume and size with use of the pony motor. Unit 1’s pony motor was subsequently removed from service and the indications continue to be tracked with regular inspections. Since the pony motor is no longer used to start the unit in pump mode, the indications have not grown, nor have new indications been noted. However, an analysis acquired by Toshiba at the Company’s request has subsequently shown that the rotor material is beyond its fatigue life limit, which explains the continued crack growth with Unit 1’s pony motor use. The major risk is that if cracks begin to grow again, the whole unit must be taken off line to protect the rest of the unit from failure. The pony motor will remain unavailable to start the unit as a pump until the pony motor rotor is replaced. And if the cracks begin to propagate again, the unit will be taken off line entirely until the pony motor rotor can be replaced;

- Replace 480V DLCs (\$1,352,043). The scope of this project is the replacement of the 20 480V DLCs over a six-year period that began in 2020 at a capital expenditure amount of \$0.671 million. The DLCs are original plant equipment and suffer from corrosion and deterioration. The primary purpose of the DLCs is to distribute power to 193 dike drain pumps and 34 pumping relief wells located around the reservoir. The purpose of the dike drain pumps is to keep the upstream face of the dike in a drained condition and to protect the asphalt liner from damage due to differential pressure. The purpose of the pumping relief wells is to keep groundwater at pre-construction levels, thereby minimizing the likelihood of a downstream slope failure. Replacement of the DLCs over a six-year period will provide high electrical system reliability and ensure FERC compliance; and

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- Governor Replacement (\$2,125,719). The scope of this project is to contract with a specialized vendor to inspect, repair as required, and modernize the unit governors. The LPS unit governors have not been overhauled in approximately 15 years and, as a result, show signs of significant wear.

The following projects are less than \$1 million but are important to regulatory compliance and reliability:

- LPS Commons Station Power Transformer (“SPT”) Life Cycle Management (\$643,137). The scope of this project is to procure and replace all six SPTs with new to suit size and configuration in current LPS footprint. The SPTs are original to the site and are in service outdoors on the LPS roof. The benefits of the project are restoration of system voltage to rated, increase site equipment life span, enablement of the ability to perform routine maintenance without risk of damage, and reduction in the probability of failure and the associated risk of not having a spare;
- Intake Gate and Gate House Mechanical Replacement (\$937,863). The LPS intake gates and associated hoist equipment are the primary form of mechanical protection for the LPS units. Their purpose is to isolate the stored energy from the reservoir’s water against each unit’s penstock when dewatering or during emergency conditions such as a penstock rupture or governor failure. Reliable operation of this system is critical to minimize damages from a unit run away condition or a penstock failure, acting as a last effort to control unit overspeed. The mechanical system of the intake gate hoist is all original (circa 1971) and recent OEM inspection revealed that its condition is poor and in need of refurbishment. Updates and repairs are required to support the current facility license extension of 2069. The electrical control system is well past its design service life. This outdated technology is obsolete, and certain critical components are no longer available for spare parts. Modern technology offers more reliable options that would give the system an additional 30 years of service. The head gate hoist is enclosed in a steel structure on top of the intake (head gate enclosure). The head gate hoist enclosures are original to the plant and have rusted out in many places. Significant corrosion has been noted on the steel frame, the connections, and the beams. These enclosures need to be replaced as they are beyond a repair option;
- Generator Potential Transformer and Enclosure Project (\$605,621). Each LPS Unit utilizes six Potential Transformers (“PT”) for Unit metering and regulating. A PT converts high primary voltage into a measurable low secondary voltage. The Metering PTs are utilized for indication of the Unit I/O and for the Disturbance Monitoring Equipment (“DME”). The Regulating PTs are utilized for Unit control and protection schemes. The current Unit metering and regulating PTs are plant original and have surpassed their life expectancy of 20-30 years. Occasionally, there have been unexplainable Unit trips due to a “PT Fail” alarm captured by the unit Exciters. This could be caused by a PT

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starting to fail. Most PT casings show their age in the form of cracks and separation of the molded casing. This can allow moisture ingress and internal insulating material loss. This can cause corrosion and overheating, ultimately leading to failure of the PT. The PTs are unlikely to last another 5-10 years and are suspected in the unexplained Unit trips. The PT enclosures are also original to the plant. There are three enclosures per unit, one for each phase (X,Y,Z). Each of the enclosures houses two drawers for the PTs, one regulating and one metering PT. The drawers have become difficult to open and close due to worn hardware. The enclosures also create a section of Isophase Phase Bus ("IPB") Duct for the IPB that connects the unit to the Starting Bus. This section of IPB Duct has been showing signs of damage due to eddy currents. This area is also a common Temporary Ground locations for workers protection during Unit and Starting Bus maintenance. The enclosure doors, where temporary grounds are installed, utilize an insert and bolt. These inserts increasingly become dislodged and fall into the Starting Bus. This causes emergent Working Clearance requirements to retrieve the inserts, so damage can't be caused by these inserts. Once an insert becomes dislodged, the insert hole becomes enlarged, and the insert can't be re- installed;

- Replace Barrier Net Panels (\$369,000). The panels are a regulatory required system to minimize fish entrainment. The panel replacements are primarily time based. LPS has extensive operating experience with these panels, which helps determine when a replacement is required; and
- Sixteen additional projects at Ludington totaling \$1.542 million, with each individual project representing \$227,778 or less in capital expenditures. These projects include Main Transformer Bank ("MTB") isophase cooling blower replacement, oil processing equipment replacement, guide bearing oil float replacement, unit thrust bearing strainer & differential pressure transmitter replacement, flow transmitter replacement, and small tools, pumps, motors, valves, and instrumentation.

ADMINISTRATIVE AND OTHER

Q. Please explain the Company's projected capital expenditures for the 16-month projected bridge period ending April 30, 2026 and the projected test year ending April 30, 2027 for Administrative and Other.

A. The Company plans to invest \$17.782 million in the 16-month projected bridge period and \$11.050 million in the projected test year in Administrative and Other, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 3, line 64, columns (h) and (j), respectively.

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1 **Q. What is the basis for the projected \$17.782 million capital investment in the 16-month**
2 **projected bridge period for Administrative and Other?**

3 A. The projected \$17.782 million capital investment in the 16-month projected bridge period
4 will fund environmental, reliability, and infrastructure projects. There are two projects
5 which are greater than \$1 million, and they are presented on Exhibit A-12 (RTB-3),
6 Schedule B-5.2, page 8, lines 27-28. The basis for those projects is described below:

- 7 • Wastewater Treatment System (\$12,400,004). This project spans the 16-month
8 projected bridge period and the projected test year, and its basis is included in
9 my discussion of the projected test year capital projects for Administrative and
10 other;
- 11 • Lakeshore Administration Building (\$3,702,428). The scope of this project is
12 to move the machine shop. The existing machine shop is located at the
13 Campbell site and with the closure of the Campbell units on May 31, 2025, the
14 Company will have to relocate the existing machine shop. Options for the
15 project include (1) doing nothing and going to third parties for parts which will
16 impact both cost and timing of delivery, (2) purchasing another machine shop,
17 (3) section off the training center at Campbell and move the machine shop to
18 that building, and (4) building a machine shop in a centralized location to better
19 service all generation sites.

20 The machine shop has proven its financial viability, routinely producing
21 annual revenues that are near or exceed annual operating costs. That trend is
22 expected to continue based on projections. The shop's ability to quickly turn
23 around projects and fabricate parts faster and at a lower cost than external
24 vendors has led to substantial savings, particularly in replacement power costs,
25 estimated at \$300k annually.

- 26 • In addition to the two projects above, there are eight additional projects totaling
27 \$1.679 million. These projects include generation cyber security, laptop and
28 capital business tool purchases for, Electric Supply, Environmental Services,
29 Lab Services, Business Planning and Administration, and Enterprise Project
30 Management.

31
32 **Q. What is the basis for the projected \$11.050 million capital investment in the projected**
33 **test year?**

34 A. The projected \$11.050 million capital investment in the projected test year will fund
35 regulatory compliance, reliability, and infrastructure projects. There is one project which

is greater than \$1 million, and it is presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, line 22. The basis for this project is described below:

- Wastewater Treatment System (\$9,600,001). As discussed in more detail earlier in this direct testimony, the scope of this project is the treatment of wastewater that will continue to be generated at the Campbell site following cessation of coal generation in May 2025. The Company considered several options to address the ongoing leachate water, including transport for offsite disposal, offsite treatment, on site treatment and onsite disposal. Ultimately, on-site disposal via a deep injection well was selected and is currently being permitted by EGLE and EPA. The Company also submitted an NPDES permit application revision on November 7, 2024; and
- In addition to the project described above, there are eight additional projects totaling \$1.412 million. These projects include generation cyber security, laptop and capital business tool purchases for Electric Supply, Environmental Services, Lab Services, Business Planning and Administration, and Enterprise Project Management.

BATTERY ENERGY STORAGE SYSTEMS

Q. Please explain the Company's projected capital expenditures for the 16-month projected bridge period ending April 30, 2026 and the projected test year ending April 30, 2027 for BESS.

A. The Company plans to invest \$70.614 million in the 16-month projected bridge period and \$26.392 million in the projected test year in Company-owned battery resources, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 3, line 71, columns (h) and (j), respectively.

Q. What is the basis for the projected \$70.614 million capital investment in the 16-month projected bridge period?

A. The projected \$70.614 million capital investment in the 16-month projected bridge period will fund BESS. This entire investment amount is reflected in two separate projects, Iosco and Weadock, which are each greater than \$1 million and are presented on Exhibit A-12

(RTB-3), Schedule B-5.2, page 8, lines 29 through 30. The basis for these projects is described in the direct testimony of Company witness Clark.

Q. What is the basis for the projected \$26.392 million capital investment in the projected test year?

A. The projected \$26.392 million capital investment in the projected test year will fund the BESS. This entire investment amount is reflected in two separate projects, Iosco and Weadock, which are each greater than \$1 million and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 23 through 24. The basis for those projects is described in the direct testimony of Company witness Clark.

GENERATION CAPITAL EXPENDITURES—SUMMARY

Q. Are the Company's capital expenditures in power generation reasonable and prudent?

A. Yes. As discussed, the proposed capital expenditures are directly aligned with the Company's generation asset strategy and, as a result, will provide economic value for power supply customers in the energy and resource adequacy markets. Other capital expenditures in generation are related to regulatory and environmental compliance, and thus are not discretionary. Company witnesses Clark provides additional discussion in his direct testimony.

SECTION IV

GENERATION O&M EXPENSE

Q. What are the major drivers in determining the O&M expense levels you are sponsoring in this proceeding?

A. The major drivers are identifying the funding needed to support the daily operation and maintenance of the Company's fleet of generating facilities and identifying the funding needed for certain internal organizations that support Generation Operations.

Q. For purposes of your direct testimony in this case, what does the Generation O&M cost represent?

A. In addition to the Company's generation fleet, I am sponsoring the O&M expenses for the Electric Supply Operations and PSCR organization, Electric Regulation and Strategy Implementation organization, Financial Planning organization, Renewable Energy Department, Contracts and Settlements organization, Generation Asset Management organization, Electric Sourcing and Resource Planning organization, Lean Organization, and Enterprise Project Management and Environmental Services organization.

Q. Please describe Exhibit A-43 (RTB-4), page 1, Generation Operation and Maintenance Expenses.

A. Exhibit A-43 (RTB-4), page 1, identifies the actual 2024 through 12-Months-Ending April 30, 2027 projected Generation O&M expenses. Specifically:

- Column (a) identifies each O&M expense category;
- Column (b) identifies the Actual 2024 Generation O&M expense as \$128,438,405;
- Column (c) identifies the 16-month Projected Bridge Period Generation O&M expense as \$150,445,403; and

- Column (d) identifies the Projected Test Year Generation O&M expense as \$103,732,461.

HISTORICAL O&M EXPENSE

Q. How does Consumers Energy determine the level of Generation O&M spending?

A. Consumers Energy tracks the history and projects the future maintenance needs of each generating unit. Personnel at the plants provide information on maintenance for each site or specific units. Once costs to operate and comply with regulations are prioritized, the Asset Strategy and Generation Planning organizations evaluate the plans required to maintain and/or improve the condition of the plant – weighing the estimated benefit to the customer for each project. Using this combination of information, a preliminary plan is prepared and reviewed to ensure high-priority issues are addressed and adequate resources and funding are available. After all appropriate levels of management have reviewed and approved the maintenance plan, a schedule is created. The overall objective is the safe, reliable, and cost-effective generation of electricity.

Q. How are Generation O&M expenses categorized?

A. Generation O&M expenses are categorized into four primary components – “Base,” “Environmental Operations,” “Major Maintenance,” and “Retention and Separation.”

Q. What are Base O&M expenses?

A. Base O&M expenses comprises two categories – labor and non-labor. Labor is the primary component and typically has a predictable, stable rate of increase. Because most of the Company’s generating units have been in service for years, the Company has an excellent basis upon which to make accurate forecasts. Non-labor expenses also tend to increase at a predictable rate and include items required to operate the plants. These items include but are not limited to (1) fuel (diesel and gasoline) for equipment and vehicles, (2) material,

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(3) tools, (4) cleaning supplies, (5) facilities, (6) security, and (7) road and grounds maintenance.

Q. Please explain how the 2024 Actual O&M expenses were developed.

A. The 2024 Actual O&M expenses were taken from Consumers Energy's internal accounting records.

Q. Please explain how the 16-month projected bridge period and projected test year Base O&M expenses were determined.

A. Base O&M expenses for the 16-month projected bridge period ending April 30, 2026, and projected test year ending April 30, 2027 shown on Exhibit A-43 (RTB-4), page 1, line 1, columns (c) and (d), were determined by considering staffing levels and historical spending. Total O&M expense for the years 2024 through the projected test year demonstrates average annual decreases of approximately 9.0%. As discussed later in this direct testimony, this average annual decrease primarily reflects a change in the mix of the Company's owned generating assets including the movement of renewable energy resources to the Company's renewable energy plans. Exhibit A-43 (RTB-4), page 1, lines 3 and 4, identify Adjusted O&M expenses which are new or projected to change from past years' expense levels. These include items that are required by law to maintain environmental compliance, for the safety of employees, and to support the reliability of service to customers, specifically, Environmental Operations and Major Maintenance. Exhibit A-43 (RTB-4), page 1, line 5, identifies Adjusted O&M expenses which are related to Retention and Separation expenses associated with the Campbell site. These expenses were required for the safe and reliable operation of Karn Units 1 and 2 through their May 2023 retirement and Campbell Units 1, 2, and 3 through their May 2025 retirement.

1 **Q. How do the historical and projected test year O&M expense amounts compare to**
2 **prior years?**

3 A. The 2024 historical O&M expense amount of \$128.438 million and the projected test year
4 O&M expense amount of \$103.732 million compare favorably to the actual O&M expense
5 amount for 2022; the 2022 generation O&M expense amount was \$150.031 million. The
6 projected test year O&M expense amount of \$103.732 million also compares favorably to
7 the actual O&M expense amount for 2023; the 2023 generation O&M expense amount was
8 \$118.848 million. As I previously stated, the O&M expense reductions reflect a mix of
9 generation asset changes, changes in major maintenance projects and expenses, cost
10 recovery realignment, and waste reduction measures.

11 **Q. Please explain Exhibit A-43 (RTB-4), page 2.**

12 A. Exhibit A-43 (RTB-4), page 2, presents the amounts of the projected O&M expenses that
13 were developed by applying either an inflation rate or contract rate to historical O&M
14 expense. Column (b) presents the historical O&M expense. Column (c) presents the
15 amount of the historical O&M amount to which an inflation rate or contract rate applies.
16 Columns (e) and (g) present the amounts to which an inflation rate or contract rate were
17 applied for each period, respectively. Columns (d), (f), and (h) present contract and
18 inflation increases for each respective period. Amounts that were projected using other
19 methods are included in column (i). Column (j) is the projected test year O&M and is the
20 sum of columns (b), (d), (f), (h), and (i).

1 **Q. Please explain how the various inflation and contract rates were applied to Labor,**
2 **Material, Contractor, and Non-Labor Other O&M expense on Exhibit A-43 (RTB-4),**
3 **page 2.**

4 A. The historical labor on line 1, column (b) reflects a combination of both Operating
5 Maintenance and Construction (“OM&C”) and non-represented labor. Inflation rates of
6 2.1%, 2.4%, and 2.4% were applied to labor on line 1, material on line 2, contractor on
7 line 3, and non-labor other on line 4 to develop the annual increase amounts in columns (d),
8 (f), and (h).

9 **Q. Please discuss how the adjustments on Exhibit A-43 (RTB-4), page 2, column (i) were**
10 **determined.**

11 A. As previously discussed, the Company projects the future maintenance needs of each unit.
12 The test year projected O&M expense amount of \$103.732 million reflects that evaluation.
13 Within the test year projected amount of \$103.732 million, there are a number of
14 adjustments that result in a projected amount that differs from the amount that is calculated
15 based solely on inflation.

16 **Q. Please discuss the adjustments that are reflected in the test year projected amount of**
17 **\$103.732 million.**

18 A. As previously discussed Karn Units 1 and 2 retired on May 31, 2023 pursuant to a
19 Settlement Agreement in the Company’s 2018 IRP and the Settlement Agreement reached
20 in the 2021 IRP reflects the retirement of Campbell Units 1, 2, and 3 on May 31, 2025 and
21 the addition of Covert Units 1, 2 and 3 on June 1, 2023. In addition, several O&M groups
22 have changed O&M expenses, all of which I will discuss later in this direct testimony.

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1 **Q. Please discuss the O&M expense for Karn Units 1 and 2.**

2 A. The 2024 O&M expense for Karn reflects the fact that Karn Units 1 and 2 retired on
3 May 31, 2023, leaving only Karn Units 3 and 4 operational. The actual O&M expense for
4 the Karn site in 2024 was \$14.653 million versus the projected O&M for the test year at
5 \$14.829 million, a modest annual increase of approximately 0.51%. 2024 represented the
6 first full year of Karn operation without Karn Units 1 and 2. A complete discussion of the
7 test year major maintenance for Karn Units 3 and 4 is described later in this direct
8 testimony.

9 **Q. Please discuss the decrease in O&M expense for Campbell Units 1, 2, and 3.**

10 A. The projected test year O&M expense for Campbell reflects the fact that the Campbell units
11 will have ceased operation in May 2025, prior to the end of the bridge period. The
12 projected test year expense for Campbell is \$0.279 million, a \$41.061 million reduction
13 from the actual 2024 O&M expense of \$41.340 million. A complete discussion of the test
14 year major maintenance for Campbell Units 1, 2, and 3 is described later in this direct
15 testimony.

16 **Q. Please discuss the increase in total O&M expense for Covert Units 1, 2, and 3.**

17 A. The 2024 O&M expense for Covert reflects the Company's first full year of operation for
18 Covert after taking ownership of the plant on June 1, 2023. The actual O&M expense for
19 Covert Units 1, 2, and 3 in 2024 was \$13.508 million, and the projected O&M for the test
20 year is \$14.858 million, with the biggest increase reflected in major maintenance. The
21 2024 expense for major maintenance was \$6.553 million however it is projected to total
22 \$7.771 million in the test year. A complete discussion of the test year major maintenance

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for Covert is described later in this direct testimony. The environmental operations expense and the base O&M are relatively flat from the historic year to the test year.

Q. Please discuss the increase in total O&M expense for Ludington.

A. The projected test year total O&M expense for Ludington reflects an increase of \$2.263 million from the historical year to the test year. The projected test year total O&M expense is \$11.661 million as compared to the historical year total O&M expense of \$9.399 million. A large portion of the increase in the projected test year total O&M expense is attributable to a \$1.394 million increase in major maintenance expense. A complete discussion of the test year major maintenance for Ludington is described later in this direct testimony. The balance of the increase is reflected in the base O&M expense increase of \$0.860 million.

Q. What is the basis for the increase in Ludington base O&M expense?

A. The 2024 base O&M expense for Ludington totaled \$6.017 million and the projected test year base O&M expense is \$6.877 million. There are three projects which primarily led to that increase: (1) FERC Assessments, (2) license initiatives, and (3) fish protection. The Company's 51% share of 2024 historical O&M expense for these projects was \$1.272 million, \$1.872 million and \$2.135 million respectively, for a total of \$5.280 million. The Company's share of the projected test year O&M expense for these three projects is \$1.442 million, \$2.321 million, and \$2.361 million respectively, for a total of \$6.123 million. The increase in projected expense for these three projects totals \$0.843 million, consistent with the overall base O&M increase. Each of these projects are required as part of the Company's FERC 50-year license and, as such, cannot be avoided.

1 **Q. Please discuss the increase in O&M expense for the River Hydros.**

2 A. The projected test year total O&M expense for the River Hydros reflects an increase of
3 \$3.944 million from the historical year to the test year. The projected test year total O&M
4 expense is \$15.261 million as compared to the historical year total O&M expense of
5 \$11.317 million. Most of the increase in the projected test year total O&M expense is
6 attributable to a \$2.964 million increase in major maintenance expense. A more complete
7 discussion of the test year major maintenance for the River Hydros is described later in this
8 direct testimony. The balance of the increase is reflected in base O&M expense, an
9 increase of \$0.969 million from \$6.474 million in the historical year to \$7.444 million in
10 the projected test year.

11 **Q. Why should the Commission approve the Company's projected River Hydro O&M**
12 **expense?**

13 A. Regardless of the ultimate decision on whether to divest, relicense, or decommission the
14 respective River Hydro facilities, the O&M expenses requested in this case are needed to
15 appropriately operate and maintain those facilities to ensure they are safe and legally
16 compliant. The current timeline for divestiture would not likely result in a decision to
17 divest prior to the start of the test period on May 1, 2026. As such, the Company will need
18 to continue to maintain and operate the River Hydros through a portion of the test year, at
19 a minimum.

20 Further, should the divestiture not be achieved, the Company would need to
21 continue to operate and maintain the River Hydros until such time that a decision to
22 relicense or decommission the River Hydros is made. Even with a decision to
23 decommission the River Hydros, a process that would take more than 20 years, the

1 Company would need to continue to operate and maintain the River Hydros until which
2 time they are decommissioned.

3 **Q. How does the Company propose to protect customers from excessive rates if the full**
4 **projected O&M expense for the test year is not required?**

5 A. The Company requests the Commission to approve a one-way tracker for the River Hydro
6 O&M expense. To the extent that future determinations obviate the need to reasonably and
7 prudently spend the Company's projected test year O&M expense for the River Hydros,
8 the Company proposes to refund the difference between the projected and actual amount
9 of O&M expense.

10 **Q. What does the Company mean with respect to one-way tracker?**

11 A. The Company only intends to refund the difference between the projected River Hydro
12 O&M expense and the actual River Hydro O&M expense in the event that actual expenses
13 are lower than projected, it does not propose to recover additional O&M expenses should
14 actual River Hydro O&M expense exceed the projected River Hydro O&M expense.

15 **Q. Please discuss the increase in total O&M expense for Administration and Generation**
16 **Commons.**

17 A. The projected increase in total O&M expense for Administration and Generation Commons
18 totals \$5.684 million and is due to a number of factors including the reorganization of the
19 Lean Organization, Enterprise Project Management tools and filling of vacancies, and
20 operations reliability spending. While much of this funding is initially budgeted for
21 Administration and Generation Commons, the actual O&M expense will ultimately be
22 assigned to the individual plants at which the work is performed.

1 **Q. Are the changes discussed above the only reasons for the overall reduced O&M**
2 **expense?**

3 A. No. The Company has implemented other focused cost reductions that have directly
4 impacted both the projected bridge period and test year expense. These cost reductions
5 were primarily achieved through individual waste reduction projects.

6 **Q. Please discuss some examples of waste reduction projects.**

7 A. I will discuss two of the projects with the largest identified savings. The first project is the
8 “Nine Year Unit Mechanical Interval Inspection and Replacement” project at Ludington.
9 The Company evaluated the annual scope and was able to extend the inspections without
10 adding risk to the equipment. The Company’s projected test year spend for this major
11 maintenance project is \$358,000 as compared to the projected spend of \$570,000 in its
12 prior electric rate case, Case No. U-21585.

13 Another specific project is the “Capacity Factor Used For Water and Chemicals”
14 project at Covert. The Company identified a way to minimize the required water
15 requirements for the year through improved process and scheduling, resulting in a savings
16 of approximately \$300,000. While the total projected cost for this major maintenance
17 project is slightly higher than that same project presented in the prior electric rate case,
18 Case No. U-21585, the projected cost presented in this case is much lower than it would
19 have been otherwise.

20 **ENVIRONMENTAL OPERATIONS**

21 **Q. What are Environmental Operations expenses?**

22 A. Environmental Operations expenses consist of labor and materials supporting the
23 environmental operations of the Company’s AQCS. As Federal and State emissions

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standards require cleaner air, Consumers Energy has installed AQCS to comply with these regulations. Consumers Energy deployed its full suite of AQCS devices in 2016, with 2017 being the first calendar year of operation.

On a historical basis, the largest portion of this expense was incurred at the Company's Karn and Campbell coal units. However, with the 2023 retirement of Karn Units 1 and 2 and the May 31, 2025 retirement of Campbell Units 1, 2, and 3, the total projected environmental operations expense has dropped significantly as I will discuss later in this direct testimony.

Q. Please explain how the projected Environmental Operations expenses for the projected bridge period ending April 30, 2026 and test year ending April 30, 2027 were calculated.

A. Environmental Operations expenses have primarily been a combination of O&M costs related to the environmental equipment at the Karn and Campbell sites on a historical basis. The operations component was primarily calculated using labor costs for operations and environmental waste disposal. The maintenance component is based on a combination of historical and estimated planned maintenance costs on the specific components of environmental equipment. However, as reflected on Exhibit A-43 (RTB-4), page 1, line 3, columns (b) and (d), the walk from the 2024 historical expense of \$8.539 million to the projected test year expense of \$2.045 million reflects a cost reduction of \$6.439 million despite inflationary increases. This cost reduction is a direct reflection of the retirement of Campbell Units 1, 2, and 3 on May 31, 2025. Beyond May 2025, most of the environmental expense is associated with the continued operation of Karn Units 3 and 4 as well as

1 projected environmental O&M expense at the gas-fired generating units, Ludington, and
2 the River Hydros.

3 **Q. What is the projected drop in Environmental Operations expense for the Campbell**
4 **site?**

5 A. The actual O&M expense for environmental operations for the Campbell site in 2024 was
6 \$6.513 million. The projected test year O&M expense for environmental operations for
7 the Campbell site is \$0, a reduction of \$6.513 million. As such, the balance of the
8 environmental operations O&M expense is basically flat from 2024 to the projected test
9 year, a very reasonable projection.

10 **MAJOR MAINTENANCE**

11 **Q. What are Major Maintenance expenses?**

12 A. Major Maintenance represents O&M projects that are based on asset condition or on
13 historic maintenance intervals over multiple years. To maintain and improve the
14 performance of the generating fleet, the Company performs Major Maintenance on a
15 regular basis. However, completion of Major Maintenance work can be influenced by,
16 among other things, actual operations of the generating units, availability of parts and labor,
17 and energy market conditions.

18 **Q. Please explain how the Major Maintenance O&M expenses for the 16-month**
19 **projected bridge period ending April 30, 2026 and test year ending April 30, 2027**
20 **were determined.**

21 A. Major Maintenance expenses are determined by tracking both the historical and future
22 maintenance needs for each site and unit, considering operation safety, unit reliability, and

1 maximum customer value. Individual projects are calculated in a manner similar to capital
2 projects, as discussed earlier in this direct testimony.

3 **Q. Please identify the test year Major Maintenance O&M expenses.**

4 A. The Company projects that it will incur \$32.982 million in Major Maintenance O&M
5 expenses during the test year, as identified by Exhibit A-43 (RTB-4), page 1, line 4,
6 column (d). Test year Major Maintenance expense by generating unit is presented on
7 Exhibit A-43 (RTB-4), page 3, column (d).

8 **Q. Why is Consumers Energy spending \$32.982 million in total Major Maintenance**
9 **O&M expense during the projected test year ending April 30, 2027?**

10 A. The Company is spending the majority of its total Major Maintenance expense during the
11 test year to maintain reliability. Reliability related Major Maintenance O&M expenses,
12 made predominantly during scheduled outages, allow the plants to avoid equipment issues
13 that would lead to more frequent random outages, exposing customers to potentially more
14 expensive replacement energy and capacity at market prices. Minimizing forced outages
15 by maintaining equipment improves the likelihood the unit will be available when needed
16 and minimizing damage that could result in the event of a catastrophic failure.

17 **Q. Are Major Maintenance expenses relatively consistent from year to year?**

18 A. No. Although the Company attempts to plan for controlled and consistent levels of Major
19 Maintenance, because Major Maintenance outages occur relatively infrequently, for an
20 individual unit, it is very possible to have significant year-by-year variations in the number,
21 duration, and magnitude of the required Major Maintenance work. Other factors such as
22 unforeseen equipment failure, emerging industry initiatives, unit dispatch, expected power

1 prices, unit performance, and simple timing variations can impact the cost and scheduling
2 of Major Maintenance.

3 **Q. Is it possible that changes to the Company's forecasted Major Maintenance plan**
4 **could occur?**

5 A. Yes. It is possible that the Company's forecasted Major Maintenance plan could change.
6 Equipment condition can change such that the timing of maintenance activities may need
7 to be accelerated or delayed. The Company attempts to make the best decision in balancing
8 the cost and risks associated with the operation of the equipment and attempts to minimize
9 the cost to customers. Factors such as weather, equipment and labor availability, energy
10 market conditions, and electrical system stability considerations can affect the actual
11 timing of an outage and maintenance spending.

12 **Q. Do Major Maintenance costs vary by individual generating unit(s)?**

13 A. Yes. While the Company's natural gas generating units are similar in age, they vary in
14 size, type, and design, so do the costs to maintain these units. As discussed earlier in this
15 direct testimony, the Company has LTSAs for its Covert, Jackson and Zeeland plants, with
16 two different OEMs. Because of these differences, the LTSA payments will vary
17 significantly from plant to plant as well as OEM to OEM.

18 **Q. Is it common for an electric utility to have different sizes, types, designs, and dispatch**
19 **of generating units in its generation portfolio?**

20 A. Yes. Consumers Energy is not unique in that its fleet contains units of different size, type,
21 and design.

22 **Q. What are the categories of Major Maintenance?**

23 A. Major Maintenance is broken into two categories—outage and non-outage.

1 **Q. Please describe what is included in the outage major maintenance O&M expense.**

2 A. Outage major maintenance O&M expenses are those associated with major overhauls and
3 require that the generating unit be removed from service for HRSGs and/or turbine
4 inspections and maintenance. These outages are typically scheduled on a periodic basis
5 and are required by law, insurance providers, LTSA inspections based upon unit operating
6 hours, and/or industry standards to ensure operational safety and reliability. One example
7 of a major maintenance outage is the periodic disassembly and repair of turbine control
8 and stop valves. The valves control the amount of steam going to the turbine and are
9 needed to control the unit output. During an emergency situation, for example during unit
10 electrical trip, the valves must react very quickly to stop the steam going to the turbine to
11 prevent it from overspeeding. Overspeeding the turbine can result in severe mechanical
12 damage resulting in a very long duration outage to repair, further resulting in increased cost
13 to customers for market priced electricity during the outage. Periodic maintenance of
14 turbine valves is required for personnel and equipment safety. Maintaining the valves on
15 a periodic basis ensures that the clearances and internal components operate as designed
16 and can reliably stop the turbine quickly when needed to prevent turbine or generator
17 damage.

18 **Q. Please describe the work completed in a boiler inspection.**

19 A. Boiler inspections assess the fire (outside) and steam (inside) sides of boiler tubing for
20 weaknesses that will ultimately result in water/steam leaks. After the boiler has been
21 properly opened, ventilated, and cleaned, scaffolding is constructed inside the boiler to
22 provide access to the boiler tubes. Inspections are completed using a number of different
23 methods – visual, non-destructive, and destructive. Visual and non-destructive testing are

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1 the most common methods of inspection. Non-destructive testing incorporates the use of
2 ultrasonic, x-ray, magnetic particle, or like technologies to measure pipe wall thickness.
3 Boiler tubes that are in poor condition or exceed minimum wall thickness are repaired or
4 replaced. After all repairs are complete, boiler tubes are pressure tested. Each boiler is
5 inspected on a specific time schedule, with a one-, two-, or three-year maximum interval.
6 Internal components with known problems are inspected more frequently. External
7 inspections are performed daily by Generation Operations and annually by state inspectors.

8 **Q. Please describe the work completed in a turbine inspection.**

9 A. Turbine inspections consist of disassembling, inspecting, and cleaning the different
10 components of the turbine. During the inspection, worn or damaged parts are repaired or
11 replaced to specific tolerances. Because of the extreme conditions under which these units
12 operate, the demand for uninterrupted power, and dangers associated with operating these
13 large pieces of equipment, industry standards recommend that inspections be completed
14 every seven years.

15 **Q. Please define non-outage maintenance.**

16 A. Non-outage maintenance O&M costs typically do not require the generating unit be
17 removed from service, but they are still critical to the operation of the unit. An example of
18 non-outage maintenance is Mill/Pulverizer maintenance.

Campbell Site Major Maintenance

Q. Please describe Campbell Site Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, lines 1 and 2, column (d), Campbell Units 1, 2, and 3 Major Maintenance expense is forecasted to be \$0.279 million in the projected test year ending April 30, 2027.

Q. Why is Consumers Energy projected to spend \$0.279 million in Major Maintenance on the Campbell units in the projected test year ending April 30, 2027?

A. Although the Campbell units will be retired on May 31, 2025, environmental regulations require the continued maintenance of the site landfill, water treatment plant, and site Rod Assisted Pipe system.

Karn Units 1 and 2 Major Maintenance

Q. Please describe Karn Units 1 and 2 Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 3, column (d), Karn Units 1 and 2 Major Maintenance expense is forecasted to be \$0.0 million in the projected test year ending April 30, 2027.

Covert Plant Major Maintenance

Q. Please describe the Covert Plant Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 8, column (d), the Covert Plant Major Maintenance expense is forecasted to be \$7.771 million in the projected test year ending April 30, 2027, and includes:

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- Covert Plant LTSA Major Maintenance (\$2,628,820). This is the major maintenance portion of the Mitsubishi negotiated services that cover the planned normal maintenance of each generating unit. The projected major maintenance expenses are based upon variable fees paid to Mitsubishi for maintenance services which are based on an effective fired hours basis pursuant to the LTSA. Unlike the General Electric LTSAs for the Jackson and Zeeland plants, there are no milestone payments associated with the fee structure for the Mitsubishi LTSA. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected premature failures of the equipment. This will help maximize availability and, as a result, optimize customer value for the site. Normal maintenance will ensure the Company continues reliable operation of the units;
- Covert Plant LTSA extra work Major Maintenance (\$1,585,000). This is the major maintenance portion of the Mitsubishi negotiated services that are not covered in the planned normal maintenance of each generating unit. Based on historical outage experience, there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items not covered under the LTSA that need to be addressed are labor and material to replace the following: blading, ammonia delivery system, SCR catalyst, turbine rotors, cooling towers, and turbine cooling air cooler;
- Covert Plant Capacity Factor Used For Water and Chemicals (\$1,300,000). This item provides for the city water used by the Covert Plant, and for the chemicals required to operate the water purification systems that are used to purify the makeup water prior to use;
- Reverse Osmosis System ("RO"), operation agreement (\$471,667). The scope of this project is to contract with a third party to operate and maintain the RO system;
- Covert Plant Base Outage Funding – Boiler plant equipment (\$425,000). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages;
- Covert Plant HEPS/FAC/DAST Inspections (\$712,500). This project will include the performance of regulatory required HEPS, DAST mid cycle inspection, and FAC inspection; and
- Six additional projects for Covert totaling \$648,269 in expenses, with each individual project representing \$238,702 or less in expenses. These projects include SCR cleaning annual maintenance, NERC relay and Direct Current ("DC") testing, ITC Transmission Co switchyard upgrades, gas turbine exhaust expansion joints repairs, and main inlet filters.

Karn Units 3 and 4 Major Maintenance

Q. Please describe Karn Units 3 and 4 Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 4, column (d), Karn Units 3 and 4 Major Maintenance expense is forecasted to be \$1.824million in the projected test year ending April 30, 2027, and includes:

- Karn Units 3 and 4 Periodic Outage Major Maintenance (\$300,000). The scope of this project is to perform boiler maintenance activities during scheduled periodic outages during the projected test year. Expenses include planning, engineering services, materials, and overtime labor;
- Site Commons uninterruptible power supply (“UPS”) preventative maintenance (\$160,000). The scope of this project is to perform the required preventive maintenance on the UPS system;
- Karn Units 3 and 4 Opacity Improvements (\$150,000). Karn Units 3 and 4 are unable to run on oil and gas without having opacity excursions. This project will perform critical maintenance and repairs on the equipment related to these opacity issues; and
- Fourteen additional projects for Karn Units 3 and 4 totaling \$1.214 million in expenses, with each individual project representing \$140,000 or less in expenses. These projects include critical motor major maintenance, boiler required repairs, breaker maintenance, boiler pendant cleaning, and main & station power transformer testing.

Zeeland Plant Major Maintenance

Q. Please describe Zeeland Plant Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 6, column (d), Zeeland Plant Major Maintenance expense is forecasted to be \$5.419 million in the projected test year ending April 30, 2027, and includes:

- Zeeland Plant LTSA — Running Maintenance Contract (\$2,395,766). Consumers Energy has a long-term maintenance agreement with General Electric to perform the major maintenance and capital repairs necessary to

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maintain unit reliability. This item represents the O&M component of that service agreement;

- Zeeland Plant Capacity Factor Used for Water and Chemicals (\$1,293,615). This item provides for the city water used by the Zeeland Plant, and for the chemicals required to operate the water purification systems that are used to purify the makeup water prior to use;
- Base Outage — Boiler Plant Equipment (\$566,667). During planned and scheduled periodic outages, inspections and repairs are performed. Base boiler maintenance and outage is needed to complete condition assessment inspections of the boiler and major components, complete repairs on valves and large plant equipment, and complete repairs that are identified during shutdowns and condition assessments;
- Large Oil Filled Transformer maintenance (\$250,000). The scope of this project is to execute the 20-year major maintenance plan which includes (1) drain/process/reclaim oil, (2) perform internal inspections when drained, (3) perform planned repairs and evaluate as found conditions, and (4) perform electrical testing to internal circuits and supporting electrical components; and
- Seventeen additional projects totaling \$912,700 in expenses, with each individual project representing \$213,033 or less in expenses. These include drum level control valve overhaul, excitation and isolation transformer testing and maintenance, HEPS, FAC inspection, breaker maintenance, and NERC-required relay testing.

Jackson Plant Major Maintenance

Q. Please describe Jackson Plant Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 7, column (d), Jackson Plant Major Maintenance expense is forecasted to be \$4.112 million in the projected test year ending April 30, 2027. This forecasted expense consists of:

- Jackson Plant Capacity Factor Used for Water and Chemicals (\$2,722,395). This item provides for the city water used by the Jackson Plant and for the chemicals required to operate the water purification systems that are used to purify the makeup water prior to use. The projected expense is based upon historical monthly invoice values as well as consideration of the capital project previously discussed in this testimony for site generating water;

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- Jackson Plant Non-LTSA Turbine and jet engine repairs (\$400,000). The scope of this major maintenance is to perform jet engine repairs including bushing replacements every 12,000 hours;
- Jackson Plant LTSA — Running Maintenance Contract (\$500,000). Consumers Energy has a long-term maintenance agreement with General Electric to perform the major maintenance and capital repairs necessary to maintain unit reliability. This item represents the O&M component of that service agreement;
- Jackson Plant Base Outage - Boiler plant equipment (\$250,000). During planned and scheduled periodic outages, inspections and repairs are performed. Base boiler maintenance and outage is needed to complete condition assessment inspections of the boiler and major components, complete repairs on valves and large plant equipment, and complete repairs that are identified during shutdowns and condition assessments; and
- Five additional projects totaling \$240,081 with each individual project representing \$75,000 or less in expenses. These include pre-filter replacement, turbine building temperature control maintenance, chiller condenser cleaning, and NERC relay testing.

LPS Major Maintenance

Q. Please describe LPS Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 9, column (d), LPS Major Maintenance expense is forecasted to be \$4.708 million in the projected test year ending April 30, 2027, including:

- Fish Barrier Net - Installation, cleaning, and repairs and removal (\$2,182,503). This is a FERC regulatory requirement. The net is installed annually and maintained to meet FERC license requirements (and the requirements of a Settlement Agreement with federal and state natural resource agencies) and minimizes the impact of LPS on fish in Lake Michigan;
- Trench Feature Work (\$450,000). FERC Part 12 requires inspections to be performed on reservoirs every 5 years. This project includes performing a dam safety inspection on the upper reservoir clay liner, scour features, erosion gullies and tailrace. The annual reservoir inspection includes multi-beam sonar and side scan of the upper reservoir as well as a multi-beam sonar on the tailrace. The project is to perform engineering remediation on defects found and

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perform silica placement as necessary to remain compliant with FERC regulations;

- Scour Feature Repair Phase 2 and 3 (\$585,667). The project scope includes repairing the scour features on Units 1 and 6 by placing rip rap in the areas where rip rap has been displaced by the newer and more powerful pumping units. Construction would include filling the Unit 1 and Unit 6 scour feature areas with rip rap and fill voids with concrete, and placing 2" of concrete between the rip rap on the entire width of the rip rap apron to a length of about 400'. This would lock in the rip rap throughout the entire width of the 2' rip rap apron and prevent the rip rap apron from being scoured away.

The rip rap apron has experienced more scour due to the upgraded pumping units. The rip rap gets displaced, exposing the filter cloth underneath the rip rap and protecting the clay liner. Once the filter cloth is exposed, it historically has gotten ripped by the pumping units and exposed to the clay liner and potential scour. During the 2019 trench features inspection, the exposed fabric was ripped, exposing the clay liner in front of Unit 6 and allowing for the clay liner to be scoured away. The rip rap apron in front of Unit 1 has also experienced scour, which has moved riprap stone and exposed fabric on top of the clay liner. Since October 2019, the area of exposed clay in front of Unit 6 has grown from 6' diameter to 20' diameter and 1.5' of the 7-8' clay liner has scoured away.

The Company has committed to FERC that it would engineer a repair to address these recurring issues in 2020; engineering was complete in April 2020 and submitted to FERC for FERC approval. In February 2020, the Dam Safety Surveillance Monitoring Committee ("SMC") created threshold action levels for the scour features in concurrence with the Engineer of Record for the scour feature repair. At 0-1 ft of scour of the clay liner, no actions are necessary. At 1-2 ft of scour of the clay liner, the scour feature shall be inspected in the next May or October outage. At 2-4 ft of scour of the clay liner, an emergent repair is needed;

- Nine Year Unit Mechanical Interval Inspection and Replacement (\$358,000). The scope of this project is to perform replacement of common wear elements and consumable items associated with the pump/turbine units. This work will include the first nine-year maintenance interval for each of the six;
- Generator Circuit Breaker ("GCB") Pumping Pole Maintenance (\$200,000). This project will fund the work scope to annually rebuild the pump poles across the site to restore their operational life as per the GCB maintenance strategy. Expected duty cycles and wear rates observed will require the site to average one pump pole set per year with an associated cost around \$200k annually for the site to perform the required maintenance items to restore. This project is only for the pump poles and not the generating poles.

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The GCB contact assembly is configured with both main and arcing contacts. The arcing contacts are designed to be "sacrificial" to prolong the main contact life. The GCB cannot safely operate under a fault condition once the arcing contact life is expended at 25% life remaining, which will force the unit to be unavailable in pump mode operations until the proper maintenance is performed. The GCB pole maintenance must be addressed in a planned outage prior to reaching 25% calculated life remaining to mitigate costs of an individual outage just for GCB maintenance; and

- Twenty-three additional projects totaling \$932,059, with each individual project representing less than \$161,000 in expenses. These include Station Drainage Sump and oil/water separator cleaning, wicket gate repair, Depression Air Compressor Maintenance, periodic outage inspections and non-destructive examination, 480v Transfer bus clean and inspection, and Non-Destructive Inspection Of Insulated And Critical Piping Systems.

Hydro Major Maintenance

Q. Please describe Hydro Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 10, column (d), Hydro Major Maintenance expense is forecasted to be \$8.374 million in the projected test year ending April 30, 2027, and includes:

- Hydro License Initiatives (\$2,107,041). A FERC requirement, this item resulted from the relicensing of Au Sable, Manistee, and Muskegon River dams, with the main result being that the Company has annual license commitments. License commitments include some recreation, fish payments, and water quality such as upwelling systems licenses;
- Hydro annual FERC Dam Safety Requirements including Part 12 Inspections (\$1,441,220). The scope of this project is to perform the FERC-required dam safety inspections on an annual basis, and the FERC-required Part 12 inspections on each dam every five years. A similar level of expense, including modest escalation, is budgeted annually from 2026 through 2029;
- Foote Auxiliary Spillway Pilot Channel and Embankment Crest Grading Project (\$1,000,000). The scope of this project is to develop a design to raise or fill the existing auxiliary spillway pilot channel/ditch. In addition, repairs to the observed rutting and grading the right embankment crest, along with placing new fill as needed, will bring the embankment to a consistent elevation of 647.0 feet. This also includes the non-corewall section embankment widening, dependent on the results from the stability analyses.

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1 Raising the elevation of the auxiliary spillway pilot channel/ditch would
2 reduce the chance of the auxiliary spillway being activated. Repairing the
3 rutting and placing new fill on the embankments would increase the slope
4 stability factor of safety, thus reducing the chance of dam failure. This project
5 will meet FERC requirements and mitigate regulatory compliance risk.

6 The Part 12D Dam safety inspection by an independent consultant noted
7 several critical issues with the Foote Auxiliary Spillway. Flow within the
8 auxiliary spillway would initiate in the pilot channel/ditch at approximately
9 elevation 641 feet, which is 0.9 feet below the current Probable Maximum
10 Flood elevation of 641.9 feet. Additionally, rutting was observed on the right
11 embankment, and the elevation survey of the left embankment showed a
12 decrease of approximately 0.7 feet at Station 0+50 since the August 2013
13 survey. Elevations measured from Sta. 1+00 to Sta. 7+50 were below the
14 nominal embankment crest of elevation 647.0 feet, with a minimum of elevation
15 646.6 feet at Sta. 3+00.

16 Failure to comply with the Dam safety inspection recommendations could
17 result in regulatory agency action, including fines and potential loss of the
18 facility's operating license. For this project, the risk being mitigated is not the
19 risk of a probable maximum flood happening but the risk of FERC citing the
20 company for regulatory non-compliance and assessing fines accordingly. This
21 risk is significant given inspection result recommendations and operating
22 license commitments.

- 23 • Hardy Intake Tower Brick Repair (\$800,000). The scope of this project is to
24 replace all the deteriorated interior brick inside the intake tower for the full
25 height. The Hardy intake tower brickwork has been slowly deteriorating for the
26 last few years. The bricks are crumbling to the touch and there are areas with
27 significant delamination throughout the entire height of the walls (34ft). If the
28 deterioration becomes significant enough, it may impact the headgate hoists and
29 the head gates installation safety of the Operations staff;
- 30 • Tippy Spillway Chamber Inspections and Repairs (\$292,667). The project
31 scope includes performing spillway chamber inspections, engineering for
32 spillway chamber repairs and construction of repairs. The Tippy spillway
33 chambers are hollow chambers underneath the spillway. In the spillway
34 chambers, the concrete is deteriorated, rebar is exposed, and there is seepage
35 present;
- 36 • Hydro Concrete Repairs (\$243,100). The scope of this project is to make
37 necessary repairs to deteriorating concrete at all 13 River Hydro facilities. This
38 budgeted amount will allow for the performance of necessary repairs which are
39 identified after spring flows or general deterioration. The identification of large
40 concrete repairs will be considered in the annual budgeting process;

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- Five Channels Intake Deck Beam Bottom Side Repairs (\$240,000). The scope of this project is the completion of partial depth concrete repairs and cleaning and applying coatings to steel areas of degradation. This option removes the areas that have experienced degradation and thereby eliminates the ongoing debris loading hazard.

The Five Channels intake deck over the penstocks is a reinforced concrete slab, spanning upstream to downstream between intermediate concrete and steel support beams running (dam convention) left to right between penstock walls. The underside of the slab and support beams are exposed to the penstock environment. In 2018 a Condition Assessment was completed of the Five Channels Unit 1 and Unit 2 penstocks. From this assessment, it was identified that the reinforced concrete beam at the upper to lower deck transition in both Units 1 and 2 had experienced concrete spalling with reinforcement being exposed. Similarly, the steel beams supporting concrete haunches to the deck above had corrosion and spalling concrete. During the 2022 Headgate replacement project, these assessments were updated, revealing significant progression of deterioration on the Unit 2 concrete beam, with the lower layer of reinforcement completely exposed, and the second layer partially exposed. Unit 1 had similar progression, to a lesser extent. The problem associated with these observations is that the degraded/missing concrete and exposed reinforcement compromises the strength of the beam, and by extension the deck. The concrete spalling represents a debris hazard for concrete debris to the turbines below;

- Cooke Powerhouse Divider wall Pier (\$206,667). The scope of this project is to assess the condition of the divider pier between the powerhouse and the spillway and make repairs as needed to the diagonal cracking observed during the dive inspections and additional deterioration noted above water. The Part 12D independent consultant and third-party condition assessment consultant noted significant diagonal cracking in the divider pier between the powerhouse and the training wall (log chute) during the dive inspection. The underwater inspection indicated the diagonal crack is approximately 11-feet long and up to 3/8" wide. The diagonal cracking may be indicative of settlement. Other minor cracks, spalls, erosion, efflorescence, delamination, and vegetation growing in cracks are also located on the divider pier; and
- Thirty-one additional projects totaling \$2,043,000 with each individual project representing \$180,000 or less in expenses. These projects include Tippy and Cooke Log Chute Concrete Repairs, base outage funding, headgate evaluation and repairs, relief well piezometer cleaning, and condition/risk assessments.

Admin and Other Major Maintenance

Q. Please describe Admin and Other Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 12, column (d), Admin and Other Major Maintenance expense is forecasted to be \$0.150 million in the projected test year ending April 30, 2027 and includes one project: Generation control systems cyber maintenance software support. Specifically, this project provides funding for software maintenance contracts from multiple vendor systems that are not part of the DCS control vendor service contracts.

Classic 7 Major Maintenance

Q. Please describe Classic 7 (Cobb, Weadock, and Whiting units) Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 5, column (d), Classic 7 Major Maintenance expense is forecasted to be \$0.218 million in the projected test year ending April 30, 2027.

Q. Why is Consumers Energy projecting to spend \$0.218 million in Major Maintenance on the Classic 7 units in the projected test year ending April 30, 2027?

A. Although the Classic 7 units were retired in 2016, environmental regulations require the continued maintenance of the on-site ash ponds, which includes Cobb landfill and ash pond O&M, Weadock landfill license and inspections, and Whiting ash pond post-closure care.

KARN AND CAMPBELL RETENTION AND SEPARATION PLAN EXPENSE

Q. What are the projected costs for the Company's Karn and Campbell Retention and Separation plans?

A. As reflected on Exhibit A-43 (RTB-4), page 1, line 5, the Company incurred actual expense of \$8.626 million in 2024, and is projecting expense of \$5.182 million in the 16-month projected bridge period ending April 30, 2026. The actual 2024 expense of \$8.626 million is based upon expense of \$0.495 million for Karn and \$8.626 million for Campbell. The 16-month projected bridge period expense of \$5.182 million is entirely based upon expense of \$5.182 million for Campbell. There is no projected test year expense.

Q. Is the Company requesting O&M recovery of the \$5.182 million projected amount for the projected bridge period?

A. No. The Company is not requesting approval of this projected amount in Generation O&M expense. The Company received approval in Electric Rate Case No. U-20697, to defer the recovery of the Karn Retention and Separation O&M amounts for 2021 through 2023. The Company received approval to defer the recovery of the Campbell retention and separation amounts in the Settlement Agreement in its 2021 IRP. As such, the projected amounts for 2024 through the projected bridge period ending April 30, 2026 are not included in the Total O&M amounts on Exhibit A-43 (RTB-4), page 1, line 6, columns (b), (c) and (d). Company witness Daly supports regulatory asset treatment of these expenses in his direct testimony.

Q. Please describe the Karn retention and separation plan.

A. The Karn retention and separation plan was a people strategy that the Company had implemented to ensure that it could retain the necessary qualified employees to operate Karn Units 1 and 2 through their retirement date in May 2023, as well as during the cold

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1 and dark time period following retirement. The cold and dark condition refers to the period
2 following plant retirement and prior to plant decommissioning. During this period, limited
3 environmental remediation and perhaps partial demolition is performed. The facility may
4 be physically secured with fencing and other measures to prevent vandalism or theft so as
5 to limit liability risks. On June 7, 2019, the MPSC approved the Company's 2018 IRP
6 Settlement Agreement, which included the retirement of Karn Units 1 and 2 in May 2023.
7 The Company's IRP included detailed support of the Company's need to implement a
8 retention and separation plan to ensure that it could operate the plants safely and reliably
9 through their retirement date.

10 **Q. What is the purpose of the retention component of the Company's plan?**

11 A. The Company had a strong interest in keeping qualified employees working at Karn Units 1
12 and 2 through their retirement date to ensure safe and reliable operations. The retention
13 component allowed the Company to retain employees that may seek employment at other
14 Company locations or outside of the Company. The Company's ability to hire new
15 employees at Karn Units 1 and 2 became increasingly difficult given the short remaining
16 lifespan of the units and, to the extent that the Company had the ability to hire new
17 employees, the training time necessary for any new hires provided a significant challenge
18 to operating the units both safely and reliably. The retention component utilized the best
19 practices that the Company employed in retiring the Classic 7.

20 **Q. What is the purpose of the separation component of the Company's plan?**

21 A. Now that Karn Units 1 and 2 are retired, the Company is following the terms of the
22 collective bargaining agreement for OM&C employees represented by the Utility Workers
23 Union of America ("UWUA"), and the terms of the employee handbook policy and

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1 separation plan for non-represented exempt and non-exempt employees. The structure and
2 amount of the severance offers varies based on employee salary and classification due to
3 differences in the terms of the separation plan covering non-represented employees and the
4 bargaining agreement for UWUA-represented employees. In the event that exempt or
5 non-exempt employees cannot find placement within the Company within 60 miles of their
6 current location, they will be offered involuntary severance in accordance with the terms
7 of the Company's Salaried Separation Plan. The Company's Working Agreement with the
8 UWUA governs separation for OM&C employees who elect to leave the Company rather
9 than accept a new position as well as relocation expenses if they accept a position more
10 than 60 miles away from their current location.

11 **Q. What are the benefit types associated with the Karn retention and separation plan?**

12 A. The Karn retention and separation plan includes three benefit types: retention benefits,
13 severance benefits, and relocation and moving costs.

14 **Q. Please describe the retention benefits associated with the Karn retention and**
15 **separation plan.**

16 A. The retention benefits associated with the Karn retention and separation plan include three
17 payment components: a signing incentive, annual incentives, and a final retention
18 incentive.

19 Employees received a signing incentive equal to 15% of their base pay if they
20 signed a retention agreement in October 2019. By signing the retention agreement, the
21 employee agreed to forfeit their transfer rights under the current working agreement (for
22 union employees) or under Company policy (for exempt and non-exempt employees). The
23 employee had to stay at Karn until October 31, 2020 to receive the payment; if the

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1 employee stayed until that date, the incentive was paid out to the employee within 30 days.

2 If the employee separated from the Company before October 31, 2020, the employee
3 forfeited the signing incentive.

4 Employees received an annual incentive which graduated from 20% to 30% of their
5 base pay for service each November in years 2019, 2020, and 2021, for staying at Karn and
6 rendering service for the next 12 months. The employee had to stay at Karn until
7 October 31 of the following year to receive the payment; if the employee stayed until that
8 date, the incentive was paid out to the employee within 30 days. If the employee separated
9 from the Company before October 31 of the next year, the employee forfeited the annual
10 incentive. Eligible employees received their first annual incentive payment in November
11 2020, a second payment in November 2021, and a third payment in November 2022.

12 Employees received their final retention incentive equal to 60% of their base pay
13 following plant retirement if the employee was still at Karn. The payment was intended to
14 incentivize employees to stay until the plant went cold and dark and compensate employees
15 for the service they rendered for the eight months (November 2022 through June 2023)
16 prior to the payment.

17 **Q. Please describe the severance benefits associated with the Karn retention and**
18 **separation plan.**

19 **A.** The severance benefits associated with the Karn retention and separation plan includes
20 initial recognition of a severance benefit to be paid, recognition of additional severance
21 earned (one week of pay per year of service), and recognition of the accretion of a final
22 severance benefit.

1 **Q. Why did the Company anticipate the need to make severance payments associated**
2 **with the retirement of Karn Units 1 and 2?**

3 A. The Company is proud of the fact that following the retirement of the Classic 7 in 2016,
4 all Company employees that desired to continue employment with the Company were able
5 to do so. However, the Company is also aware of the fact that it has fewer Company
6 locations (11 within 60 miles of the Karn site) to which employees could relocate, than it
7 did in 2016. As such, the Company anticipated the need to make severance payments to
8 those employees that could not find placement. As I previously stated, the Company is
9 following the terms of the collective bargaining agreement for OM&C employees
10 represented by the UWUA, and the terms of the employee handbook policy and separation
11 plan for non-represented exempt and non-exempt employees.

12 **Q. Please explain the relevant details of the collective bargaining agreement for OM&C**
13 **employees.**

14 A. The collective bargaining agreement for OM&C employees, in Article VII, Section 17, and
15 the Generation Operations Coal Closing Agreement provide that employees will be placed
16 in either a corresponding position, or if none exists, in a vacant position he/she is qualified
17 to perform within 60 miles of his/her current headquarters. Per Article XVII of the
18 collective bargaining agreement, employees who are released due to lack of work, and are
19 not placed as described above, are provided a separation allowance consisting of straight
20 time pay for five regular workdays for each year of continuous service with the
21 Company. Due to the lack of Company locations within 60 miles of Karn Units 1 and 2,
22 as described above, it was anticipated that some employees would be eligible for a
23 separation allowance.

1 **Q. Please describe the Campbell retention plan.**

2 A. The Campbell retention plan is a people strategy that the Company proposed in its 2021
3 IRP. As previously discussed, the Company's 2021 IRP PCA reflects the retirement of
4 Campbell Units 1, 2, and 3 on May 31, 2025. This retention plan was proposed in order to
5 retain employees through the closure of the three Campbell units. This strategy is
6 necessary to ensure that the Company can operate the Campbell units safely and reliably
7 through their retirement date. This incentive program is the same program that is currently
8 in place for employees at the Karn site.

9 **Q. What is the purpose of the retention component of the Company's plan?**

10 A. For similar reasons described in the Karn retention plan, the Company had a strong interest
11 in keeping qualified employees working at the Campbell site through their retirement date
12 to ensure safe and reliable operations. The retention component will allow the Company
13 to retain employees that may seek employment at other Company locations or outside of
14 the Company. Similar to the situation at the Karn site, it was increasingly difficult to hire
15 new employees at the Campbell site given the short remaining lifespan of the units and, to
16 the extent that the Company has the ability to hire new employees, the training time
17 necessary for any new hires provided a significant challenge to operating the three units
18 both safely and reliably.

19 **Q. What is the purpose of the separation component of the Company's plan?**

20 A. After the Campbell units are retired, the Company is following the terms of the collective
21 bargaining agreement for OM&C employees represented by the UWUA, and the terms of
22 the employee handbook policy and separation plan for non-represented exempt and
23 non-exempt employees. The structure and amount of the severance offers will vary

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1 based on employee salary and classification due to differences in the terms of the
2 separation plan covering non-represented employees and the bargaining agreement
3 for UWUA-represented employees. In the event that exempt or non-exempt employees
4 cannot find placement within the Company within 60 miles from their current location,
5 they will be offered involuntary severance in accordance with the terms of the Company's
6 Salaried Separation Plan. The Company's Working Agreement with the UWUA governs
7 separation for OM&C employees who elect to leave the Company rather than accept a new
8 position as well as relocation expenses if they accept a position more than 60 miles away
9 from their current location.

10 **Q. What are the benefit types associated with the Campbell retention plan?**

11 A. Similar to the Karn retention and separation plan, the Campbell retention plan includes
12 three benefit types: retention benefits, severance benefits, and relocation and moving costs.

13 **Q. Please describe the retention benefits associated with the Campbell retention plan.**

14 A. The retention benefits associated with the Campbell retention plan include three payment
15 components: a signing incentive, periodic incentives, and a final retention incentive. The
16 timeline for retention benefits reflects approval of the Settlement Agreement in the
17 Company's 2021 IRP in June 2022.

18 Employees received a signing incentive equal to 15% of their base pay if they
19 signed a retention agreement in July 2022. By signing the retention agreement, the
20 employee agreed to forfeit their transfer rights under the current working agreement (for
21 union employees) or under Company policy (for exempt and non-exempt employees). The
22 employee had to stay at Campbell until October 31, 2022 to receive the payment; if the
23 employee stayed until that date, the incentive was paid out to the employee within 30 days.

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1 If the employee separated from the Company before October 31, 2022, the employee
2 forfeited the signing incentive.

3 Employees received a periodic incentive which graduates from 20% to 30% of their
4 base pay for service each November in years 2022, 2023, and 2024, for staying at Campbell
5 and rendering service for a certain period. Specifically, for service provided July 2022
6 through October 2022, employees received 20% of their base pay. For service provided
7 November 2022 through October 2023, employees received 25% of their base pay. For
8 service provided November 2023 through October 2024, employees received 30% of their
9 base pay. The employee must stay at Campbell until October 31 of the given year to receive
10 the payment; if the employee stays until that date, the incentive was/will be paid out to the
11 employee within 30 days. If the employee separates from the Company before October 31
12 of the given year, the employee forfeits the annual incentive.

13 Employees receive a final retention incentive equal to 60% of their base pay on or
14 about October 31, 2025, if the employee is still at Campbell. The payment is intended to
15 incentivize employees to stay until the plant goes cold and dark and compensate employees
16 for the service they rendered for the 12 months prior to the payment.

17 **Q. Please describe the severance benefits associated with the Campbell retention plan.**

18 A. The severance benefits associated with the Campbell retention plan include initial
19 recognition of a severance benefit to be paid, recognition of additional severance earned
20 (one week of pay per year of service), and recognition of the accretion of a final severance
21 benefit.

1 **Q. Why does the Company anticipate the need to make severance payments associated**
2 **with the retirement of Campbell Units 1, 2, and 3?**

3 A. The Company is proud of the fact that following the retirement of the Classic 7 in 2016,
4 all Company employees who desired to continue employment with the Company were able
5 to do so. However, the Company is also aware of the fact that it has fewer Company
6 locations (seven within 60 miles of the Campbell site) to which employees can relocate,
7 than it did in 2016. In addition, the Company also retired two of the Karn generating units
8 in 2023, thereby further reducing the available positions. As such, the Company has
9 anticipated the need to make severance payments to those employees who cannot find
10 placement. As I previously stated, the Company is following the terms of the collective
11 bargaining agreement for OM&C employees represented by the UWUA, and the terms of
12 the employee handbook policy and separation plan for non-represented exempt and
13 non-exempt employees, as previously discussed for the Karn retention and separation plan.

14 **Q. Does this conclude your direct testimony?**

15 A. Yes, it does.

Schedule: B-5.2

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Summary of Actual and Projected Electric Capital Expenditures
For the years 2024 through 2027
(\$000's)

Case No.: U-21870
Exhibit No.: A-12 (RTB-3)
Schedule: B-5.2
Page: 1 of 9
Witness: RTBlumenstock
Date: June 2025

**Generation Capital Expenditures
(\$000)**

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Period			Projected Test Year
		12 Months Ended 12/31/2024	12 Mos Ended 12/31/2025	4 Mos Ending 4/30/2026	16 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027
1	Steam Power Generation					
2	Environmental	\$ -	\$ -	\$ -	\$ -	\$ -
3	Routine and Small CapEx	\$ 22,814	\$ 9,200	\$ 3,278	\$ 12,478	\$ 8,304
4	Total Steam Production	\$ 22,814	\$ 9,200	\$ 3,278	\$ 12,478	\$ 8,304
5	Hydraulic Power Generation					
6	Routine and Small CapEx	\$ -	\$ -	\$ -	\$ -	\$ -
7	Total hydraulic production	\$ -	\$ -	\$ -	\$ -	\$ -
8	Pumped Storage Generation					
9	Ludington Overhaul	\$ -	\$ -	\$ -	\$ -	\$ -
10	Routine and Small CapEx	\$ 2,710	\$ 11,418	\$ 3,807	\$ 15,225	\$ 13,282
11	Total Pumped Storage Generation	\$ 2,710	\$ 11,418	\$ 3,807	\$ 15,225	\$ 13,282
12	Other Production Plant					
13	Routine and Small CapEx	\$ 119,728	\$ 173,227	\$ 74,477	\$ 247,705	\$ 167,051
14	Total Other Production Plant	\$ 119,728	\$ 173,227	\$ 74,477	\$ 247,705	\$ 167,051
15	SubTotal	\$ 145,252	\$ 193,846	\$ 81,562	\$ 275,408	\$ 188,638
16	Less Contingency	\$ -	\$ -	\$ -	\$ -	\$ -
17	Grand Total	\$ 145,252	\$ 193,846	\$ 81,562	\$ 275,408	\$ 188,638

	(a)	(b)	(c)	(d)	(e)
		Projected			
		4 Mos Ending 4/30/2025	12 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	28 Mos Ending 4/30/2027
1	Steam Power Generation				
2	Environmental	\$ -	\$ -	\$ -	\$ -
3	Routine and Small CapEx	\$ 1,763	\$ 10,715	\$ 8,304	\$ 20,782
4	Total Steam Production	\$ 1,763	\$ 10,715	\$ 8,304	\$ 20,782
5	Hydraulic Power Generation				
6	Routine and Small CapEx	\$ -	\$ -	\$ -	\$ -
7	Total hydraulic production	\$ -	\$ -	\$ -	\$ -
8	Pumped Storage Generation				
9	Ludington Overhaul				\$ -
10	Routine and Small CapEx	\$ 3,928	\$ 11,296	\$ 13,282	\$ 28,507
11	Total Pumped Storage Generation	\$ 3,928	\$ 11,296	\$ 13,282	\$ 28,507
12	Other Production Plant				
13	Routine and Small CapEx	\$ 89,789	\$ 157,916	\$ 167,051	\$ 414,755
14	Total Other Production Plant	\$ 89,789	\$ 157,916	\$ 167,051	\$ 414,755
15	SubTotal	\$ 95,480	\$ 179,928	\$ 188,638	\$ 464,045
16	Less Contingency	\$ -	\$ -	\$ -	\$ -
17	Grand Total	\$ 95,480	\$ 179,928	\$ 188,638	\$ 464,045

Schedule: B-5.2

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Summary of Actual and Projected Electric Capital Expenditures

For the years 2024 through 2027

(\$000's)

Case No.: U-21870

Exhibit No.: A-12 (RTB-3)

Schedule: B-5.2

Page: 2 of 9

Witness: RTBlumenstock

Date: June 2025

Generation Capital Expenditures											
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Historical Year		Projected Bridge Period							Projected Test Year
Line No.	Description	12 Months Ended 12/31/2024		12 Months Ending 12/31/2025		4 Months Ending 4/30/2026		16 Months Ending 4/30/2026		12 Months Ending 4/30/2027	
1	JHCampbell 1&2	\$	(1,510)	\$	-	\$	-	\$	-	\$	-
2	Contractor		\$ (1,274)		\$ -		\$ -		\$ -		\$ -
3	Labor		\$ (193)		\$ -		\$ -		\$ -		\$ -
4	Materials		\$ 131		\$ -		\$ -		\$ -		\$ -
5	Business Expenses		\$ (20)		\$ -		\$ -		\$ -		\$ -
6	Contingency		\$ -		\$ -		\$ -		\$ -		\$ -
7	Other (Loadings, Chargebacks)		\$ (154)		\$ -		\$ -		\$ -		\$ -
8	JHCampbell 3	\$	(1,264)	\$	-	\$	-	\$	-	\$	-
9	Contractor		\$ (1,007)		\$ -		\$ -		\$ -		\$ -
10	Labor		\$ (200)		\$ -		\$ -		\$ -		\$ -
11	Materials		\$ 150		\$ -		\$ -		\$ -		\$ -
12	Business Expenses		\$ (36)		\$ -		\$ -		\$ -		\$ -
13	Contingency		\$ -		\$ -		\$ -		\$ -		\$ -
14	Other (Loadings, Chargebacks)		\$ (171)		\$ -		\$ -		\$ -		\$ -
15	DEKarn 1&2	\$	-	\$	-	\$	-	\$	-	\$	-
16	Contractor		\$ -		\$ -		\$ -		\$ -		\$ -
17	Labor		\$ -		\$ -		\$ -		\$ -		\$ -
18	Materials		\$ -		\$ -		\$ -		\$ -		\$ -
19	Business Expenses		\$ -		\$ -		\$ -		\$ -		\$ -
20	Contingency		\$ -		\$ -		\$ -		\$ -		\$ -
21	Other (Loadings, Chargebacks)		\$ -		\$ -		\$ -		\$ -		\$ -
22	DEKarn 3&4	\$	25,587	\$	9,200	\$	3,278	\$	12,478	\$	8,304
23	Contractor		\$ 18,333		\$ 8,648		\$ 3,081		\$ 11,729		\$ 7,806
24	Labor		\$ 937		\$ -		\$ -		\$ -		\$ -
25	Materials		\$ 1,450		\$ -		\$ -		\$ -		\$ -
26	Business Expenses		\$ 56		\$ -		\$ -		\$ -		\$ -
27	Contingency		\$ -		\$ -		\$ -		\$ -		\$ -
28	Other (Loadings, Chargebacks)		\$ 4,812		\$ 552		\$ 197		\$ 749		\$ 498
29	Zeeland	\$	45,025	\$	52,002	\$	15,273	\$	67,275	\$	40,023
30	Contractor		\$ 34,570		\$ 48,882		\$ 14,356		\$ 63,239		\$ 37,621
31	Labor		\$ 588		\$ -		\$ -		\$ -		\$ -
32	Materials		\$ 3,250		\$ -		\$ -		\$ -		\$ -
33	Business Expenses		\$ 67		\$ -		\$ -		\$ -		\$ -
34	Contingency		\$ -		\$ -		\$ -		\$ -		\$ -
35	Other (Loadings, Chargebacks)		\$ 6,550		\$ 3,120		\$ 916		\$ 4,037		\$ 2,401
36	Jackson Generating Station	\$	15,255	\$	18,778	\$	5,712	\$	24,489	\$	28,143
37	Contractor		\$ 11,661		\$ 17,651		\$ 5,369		\$ 23,020		\$ 26,455
38	Labor		\$ 273		\$ -		\$ -		\$ -		\$ -
39	Materials		\$ 1,539		\$ -		\$ -		\$ -		\$ -
40	Business Expenses		\$ 5		\$ -		\$ -		\$ -		\$ -
41	Contingency		\$ -		\$ -		\$ -		\$ -		\$ -
42	Other (Loadings, Chargebacks)		\$ 1,777		\$ 1,127		\$ 343		\$ 1,469		\$ 1,689
43	Covert	\$	30,712	\$	45,054	\$	22,491	\$	67,545	\$	61,443
44	Contractor		\$ 23,628		\$ 42,350		\$ 21,142		\$ 63,492		\$ 57,756
45	Labor		\$ 113		\$ -		\$ -		\$ -		\$ -
46	Materials		\$ 3,377		\$ -		\$ -		\$ -		\$ -
47	Business Expenses		\$ 26		\$ -		\$ -		\$ -		\$ -
48	Contingency		\$ -		\$ -		\$ -		\$ -		\$ -
49	Other (Loadings, Chargebacks)		\$ 3,568		\$ 2,703		\$ 1,349		\$ 4,053		\$ 3,687

Consumers Energy Company

Summary of Actual and Projected Electric Capital Expenditures

For the years 2024 through 2027

(\$000's)

Generation Capital Expenditures

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Historical Year 12 Months Ended 12/31/2024		12 Months Ending 12/31/2025		4 Months Ending 4/30/2026		16 Months Ending 4/30/2026		Projected Test Year 12 Months Ending 4/30/2027	
50	Hydros	-		-		-		-		-	
51	Contractor		-		-		-		-		-
52	Labor		-		-		-		-		-
53	Materials		-		-		-		-		-
54	Business Expenses		-		-		-		-		-
55	Contingency		-		-		-		-		-
56	Other (Loadings, Chargebacks)		-		-		-		-		-
57	Ludington	2,710		11,418		3,807		15,225		13,282	
58	Contractor		3,299		18,041		6,015		24,055		20,986
59	Labor		402		-		-		-		-
60	Materials		885		-		-		-		-
61	Business Expenses		449		-		-		-		-
62	Contingency		-		-		-		-		-
63	Other (Loadings, Chargebacks)		(2,325)		(6,622)		(2,208)		(8,830)		(7,704)
64	Admin and Other	5,748		14,809		2,973		17,782		11,050	
65	Contractor		3,476		12,564		2,585		15,149		9,550
66	Labor		92		-		-		-		-
67	Materials		2,149		-		-		-		-
68	Business Expenses		79		-		-		-		-
69	Contingency		-		-		-		-		-
70	Other (Loadings, Chargebacks)		(48)		2,244		388		2,633		1,501
71	Battery Storage	22,988		42,585		28,029		70,614		26,392	
72	Contractor		16,777		36,470		24,004		60,473		22,602
73	Labor		207		-		-		-		-
74	Materials		2,475		-		-		-		-
75	Business Expenses		5		-		-		-		-
76	Contingency		-		-		-		-		-
77	Other (Loadings, Chargebacks)		3,525		6,115		4,025		10,140		3,790
78	All Other Environmental	-		-		-		-		-	
79	Contractor		-		-		-		-		-
80	Labor		-		-		-		-		-
81	Materials		-		-		-		-		-
82	Business Expenses		-		-		-		-		-
83	Contingency		-		-		-		-		-
84	Other (Loadings, Chargebacks)		-		-		-		-		-
85	Total Capital	145,252	145,252	193,846	193,846	81,562	81,562	275,408	275,408	188,638	188,638

Schedule: B-5.2

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Summary of Actual and Projected Electric Capital Expenditures
For the years 2024 through 2027
(\$000's)

Case No.: U-21870

Exhibit No.: A-12 (RTB-3)

Schedule: B-5.2

Page: 4 of 9

Witness: RTBlumenstock

Date: June 2025

Generation Capital Expenditures

	(a)	(b)	(c)	(d)	(e)
		Projected			
Line No.	Description	4 Mos Ending 4/30/2025	12 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	28 Mos Ending 4/30/2027
1	JHCampbell 1&2	\$ -	\$ -	\$ -	\$ -
2	Contractor	\$ -	\$ -	\$ -	\$ -
3	Labor	\$ -	\$ -	\$ -	\$ -
4	Materials	\$ -	\$ -	\$ -	\$ -
5	Business Expenses	\$ -	\$ -	\$ -	\$ -
6	Contingency	\$ -	\$ -	\$ -	\$ -
7	Other (Loadings, Chargebacks)	\$ -	\$ -	\$ -	\$ -
8	JHCampbell 3	\$ -	\$ -	\$ -	\$ -
9	Contractor	\$ -	\$ -	\$ -	\$ -
10	Labor	\$ -	\$ -	\$ -	\$ -
11	Materials	\$ -	\$ -	\$ -	\$ -
12	Business Expenses	\$ -	\$ -	\$ -	\$ -
13	Contingency	\$ -	\$ -	\$ -	\$ -
14	Other (Loadings, Chargebacks)	\$ -	\$ -	\$ -	\$ -
15	DEKarn 1&2	\$ -	\$ -	\$ -	\$ -
16	Contractor	\$ -	\$ -	\$ -	\$ -
17	Labor	\$ -	\$ -	\$ -	\$ -
18	Materials	\$ -	\$ -	\$ -	\$ -
19	Business Expenses	\$ -	\$ -	\$ -	\$ -
20	Contingency	\$ -	\$ -	\$ -	\$ -
21	Other (Loadings, Chargebacks)	\$ -	\$ -	\$ -	\$ -
22	DEKarn 3&4	\$ 1,763	\$ 10,715	\$ 8,304	\$ 20,782
23	Contractor	\$ 1,635	\$ 10,094	\$ 7,806	\$ 19,535
24	Labor	\$ -	\$ -	\$ -	\$ -
25	Materials	\$ -	\$ -	\$ -	\$ -
26	Business Expenses	\$ -	\$ -	\$ -	\$ -
27	Contingency	\$ -	\$ -	\$ -	\$ -
28	Other (Loadings, Chargebacks)	\$ 127	\$ 621	\$ 498	\$ 1,247
29	Zeeland	\$ 33,232	\$ 34,043	\$ 40,023	\$ 107,298
30	Contractor	\$ 32,099	\$ 31,140	\$ 37,621	\$ 100,860
31	Labor	\$ -	\$ -	\$ -	\$ -
32	Materials	\$ -	\$ -	\$ -	\$ -
33	Business Expenses	\$ -	\$ -	\$ -	\$ -
34	Contingency	\$ -	\$ -	\$ -	\$ -
35	Other (Loadings, Chargebacks)	\$ 1,133	\$ 2,903	\$ 2,401	\$ 6,438
36	Jackson Generating Station	\$ 4,499	\$ 19,991	\$ 28,143	\$ 52,633
37	Contractor	\$ 4,340	\$ 18,680	\$ 26,455	\$ 49,475
38	Labor	\$ -	\$ -	\$ -	\$ -
39	Materials	\$ -	\$ -	\$ -	\$ -
40	Business Expenses	\$ -	\$ -	\$ -	\$ -
41	Contingency	\$ -	\$ -	\$ -	\$ -
42	Other (Loadings, Chargebacks)	\$ 158	\$ 1,311	\$ 1,689	\$ 3,158
43	Covert	\$ 16,058	\$ 51,487	\$ 61,443	\$ 128,988
44	Contractor	\$ 14,977	\$ 48,515	\$ 57,756	\$ 121,248
45	Labor	\$ -	\$ -	\$ -	\$ -
46	Materials	\$ -	\$ -	\$ -	\$ -
47	Business Expenses	\$ -	\$ -	\$ -	\$ -
48	Contingency	\$ -	\$ -	\$ -	\$ -
49	Other (Loadings, Chargebacks)	\$ 1,080	\$ 2,972	\$ 3,687	\$ 7,739

Schedule: B-5.2

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Summary of Actual and Projected Electric Capital Expenditures
For the years 2024 through 2027
(\$000's)

Case No.: U-21870

Exhibit No.: A-12 (RTB-3)

Schedule: B-5.2

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Witness: RTBlumenstock

Date: June 2025

Generation Capital Expenditures

Line No.	(a) Description	Projected			
		(b) 4 Mos Ending 4/30/2025	(c) 12 Mos Ending 4/30/2026	(d) 12 Mos Ending 4/30/2027	(e) 28 Mos Ending 4/30/2027
50	Hydros	\$ -	\$ -	\$ -	\$ -
51	Contractor	\$ -	\$ -	\$ -	\$ -
52	Labor	\$ -	\$ -	\$ -	\$ -
53	Materials	\$ -	\$ -	\$ -	\$ -
54	Business Expenses	\$ -	\$ -	\$ -	\$ -
55	Contingency	\$ -	\$ -	\$ -	\$ -
56	Other (Loadings, Chargebacks)	\$ -	\$ -	\$ -	\$ -
57	Ludington	\$ 3,928	\$ 11,296	\$ 13,282	\$ 28,507
58	Contractor	\$ 6,865	\$ 17,190	\$ 20,986	\$ 45,041
59	Labor	\$ -	\$ -	\$ -	\$ -
60	Materials	\$ -	\$ -	\$ -	\$ -
61	Business Expenses	\$ -	\$ -	\$ -	\$ -
62	Contingency	\$ -	\$ -	\$ -	\$ -
63	Other (Loadings, Chargebacks)	\$ (2,937)	\$ (5,893)	\$ (7,704)	\$ (16,534)
64	Admin and Other	\$ 2,477	\$ 15,305	\$ 11,050	\$ 28,832
65	Contractor	\$ 2,145	\$ 13,004	\$ 9,550	\$ 24,699
66	Labor	\$ -	\$ -	\$ -	\$ -
67	Materials	\$ -	\$ -	\$ -	\$ -
68	Business Expenses	\$ -	\$ -	\$ -	\$ -
69	Contingency	\$ -	\$ -	\$ -	\$ -
70	Other (Loadings, Chargebacks)	\$ 332	\$ 2,300	\$ 1,501	\$ 4,133
71	Battery Storage	\$ 33,523	\$ 37,091	\$ 26,392	\$ 97,006
72	Contractor	\$ 28,709	\$ 31,764	\$ 22,602	\$ 83,075
73	Labor	\$ -	\$ -	\$ -	\$ -
74	Materials	\$ -	\$ -	\$ -	\$ -
75	Business Expenses	\$ -	\$ -	\$ -	\$ -
76	Contingency	\$ -	\$ -	\$ -	\$ -
77	Other (Loadings, Chargebacks)	\$ 4,814	\$ 5,326	\$ 3,790	\$ 13,930
78	All Other Environmental	\$ -	\$ -	\$ -	\$ -
79	Contractor	\$ -	\$ -	\$ -	\$ -
80	Labor	\$ -	\$ -	\$ -	\$ -
81	Materials	\$ -	\$ -	\$ -	\$ -
82	Business Expenses	\$ -	\$ -	\$ -	\$ -
83	Contingency	\$ -	\$ -	\$ -	\$ -
84	Other (Loadings, Chargebacks)	\$ -	\$ -	\$ -	\$ -
85	SubTotal	\$ 95,480	\$ 179,928	\$ 188,638	\$ 464,045
86	Less Contingency	\$ -	\$ -	\$ -	\$ -
87	Grand Total	\$ 95,480	\$ 179,928	\$ 188,638	\$ 464,045

Schedule: B-5.2

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Summary of Actual and Projected Electric Capital Expenditures
For the years 2024 through 2027

(\$000's)

Case No.: U-21870

Exhibit No.: A-12 (RTB-3)

Schedule: B-5.2

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Witness: RTBlumenstock

Date: June 2025

Generation Capital Expenditures

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Period			Projected Test Year
		12 Months Ended 12/31/2024	12 Months Ending 12/31/2025	4 Months Ending 4/30/2026	16 Months Ending 4/30/2026	12 Months Ending 4/30/2027
1	Contractor	\$ 109,462	\$ 184,607	\$ 76,551	\$ 261,158	\$ 182,776
2	Labor	\$ 2,219	\$ -	\$ -	\$ -	\$ -
3	Materials	\$ 15,405	\$ -	\$ -	\$ -	\$ -
4	Business Expenses	\$ 632	\$ -	\$ -	\$ -	\$ -
5	Contingency	\$ -	\$ -	\$ -	\$ -	\$ -
6	Other (Loadings, Chargebacks)	\$ 17,533	\$ 9,239	\$ 5,011	\$ 14,250	\$ 5,862
	Total	\$ 145,252	\$ 193,846	\$ 81,562	\$ 275,408	\$ 188,638

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)
		12 Months Ended 12/31/2024	Projected			28 Months Ending 4/30/2027
		12 Months Ended 12/31/2024	4 Months Ending 4/30/2025	16 Months Ending 4/30/2026	12 Months Ending 4/30/2027	28 Months Ending 4/30/2027
1	Contractor	\$ 109,462	\$ 90,771	\$ 261,158	\$ 182,776	\$ 443,934
2	Labor	\$ 2,219	\$ -	\$ -	\$ -	\$ -
3	Materials	\$ 15,405	\$ -	\$ -	\$ -	\$ -
4	Business Expenses	\$ 632	\$ -	\$ -	\$ -	\$ -
5	Contingency	\$ -	\$ -	\$ -	\$ -	\$ -
6	Other (Loadings, Chargebacks)	\$ 17,533	\$ 4,709	\$ 14,250	\$ 5,862	\$ 20,111
	Total	\$ 145,252	\$ 95,480	\$ 275,408	\$ 188,638	\$ 464,045

Schedule: B-5.2

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Summary of Actual and Projected Electric Capital Expenditures

For the years 2024 through 2027

(\$000's)

Case No.: U-21870

Exhibit No.: A-12 (RTB-3)

Schedule: B-5.2

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Witness: RTBlumenstock

Date: June 2025

Generation Capital Expenditures

Line No.	(a) Calendar Year	(b) Tier 1 Portfolio	(c) Tier 2 Portfolio	(d) Project Type	(e) Project Classification	(f) Work Item Description	(g) Projected Amount	(h) Actual Amount
1	2024	Gas Generation	Covert	Non-Routine	Condition-based	Long Term Service Agreement - Running capital contrac	\$ 19,004	\$ 15,623
2	2024	Gas Generation	Covert	Routine	Condition-based	Netmation (MHPSA Operating System & 4S) - Unit 1-5	\$ 4,596	\$ 6,047
3	2024	Gas Generation	Covert	Routine	Environmental	Long Term Service Agreement - Extra Work Unit 2	\$ 750	\$ 1,340
4	2024	Gas Generation	Covert	Routine	Environmental	HRSB Expansion Joint Replacements	\$ -	\$ 1,284
5	2024	Gas Generation	Jackson	Routine	Condition-based	1-6 Feedwater Desuperheater Valve	\$ 831	\$ 1,871
6	2024	Gas Generation	Jackson	Routine	Condition-based	GE Long Term Service Agreement FFH	\$ 12,213	\$ 8,615
7	2024	Gas Generation	Zeeland	Non-Routine	Condition-based	Unit 5 generator step up transformer rewinc	\$ 9,135	\$ 9,696
8	2024	Gas Generation	Zeeland	Non-Routine	Condition-based	Site Spare GSU	\$ 590	\$ 2,040
9	2024	Gas Generation	Zeeland	Routine	Condition-based	P2 599 699 345kV Breaker Replcmnt	\$ 320	\$ 1,856
10	2024	Gas Generation	Zeeland	Routine	Condition-based	Zeeland Long Term Service Agreement - Running Capital Contrac	\$ 19,641	\$ 21,699
11	2024	Gas Generation	Zeeland	Non-Routine	Condition-based	Heat recovery steam generator Casing Replacemen	\$ 2,739	\$ 2,840
12	2024	Gas/Oil Generation	Karn 3	Routine	Condition-based	Karn 3 distributed control system Evergreer	\$ 1,295	\$ 1,191
13	2024	Gas/Oil Generation	Karn 3	Non-Routine	Condition-based	Karn 3 Cooling Tower Internal Structure Replacemen	\$ 3,919	\$ 4,183
14	2024	Gas/Oil Generation	Karn 3	Routine	Condition-based	Karn 3 Combustion Air Heater	\$ 2,500	\$ 1,354
15	2024	Gas/Oil Generation	Karn commons	Routine	Condition-based	Karn 3&4 Sync Wire Replacement	\$ 1,458	\$ 1,260
16	2024	Gas/Oil Generation	Karn commons	Non-Routine	Condition-based	Boiler Plant Heating Project	\$ 3,055	\$ 4,467
17	2024	Gas/Oil Generation	Karn commons	Non-Routine	Condition-based	Karn 3&4 Tank Farm Heating Line Replacemen	\$ 1,230	\$ 1,217
18	2024	Gas/Oil Generation	Karn commons	Non-Routine	Asset Separation	New Electrical System from Weadock Sub for Karn 3 and 4	\$ -	\$ 1,524
19	2024	Gas/Oil Generation	Karn commons	Non-Routine	Asset Separation	Discharge Line Reroute for K 3 and 4 Sump Water	\$ -	\$ 1,905
20	2024	Gas/Oil Generation	Karn commons	Non-Routine	Asset Separation	New building to house new fire water system	\$ -	\$ 1,019
21	2024	Gas/Oil Generation	Karn commons	Non-Routine	Asset Separation	New 46kV to 4160 transformer to repower facilities	\$ -	\$ 3,065
22	2024	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Iosco Battery Energy Storage System (IRP)	\$ 21,458	\$ 9,107
23	2024	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Weadock Battery Energy Storage System (IRP)	\$ 31,819	\$ 13,011
24	Total 2024 Projects						\$ 136,553	\$ 116,212

Note:

(1) Projected amounts were taken from Case No. U-21585, Staff Exhibit S-16.1 Page 1 of 2 and workpapers.

Case No.: U-21870
Exhibit No.: A-12 (RTB-3)
Schedule: B-5.2
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Witness: RTBlumenstock
Date: June 2025

Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2024 through 2027
(\$000's)

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(f)	(g)	(h)
	Calendar Period	Tier 1 Portfolio	Tier 2 Portfolio	Project Type	Project Classification	Class of Cost Estimate	Full Internal Budget Approval	Work Item Description	Projected Amount
1	Bridge Period	Gas Generation	Covert	Non-Routine	Condition-based	Class 2	Approved	Purchase of site spare GSU	\$1,500
2	Bridge Period	Gas Generation	Covert	Non-Routine	Condition-based	Class 3	Approved	LCI Replacements (SFC)	\$1,305
3	Bridge Period	Gas Generation	Covert	Routine	Condition-based	Class 2	Approved	Units 1-3 Emerson DCS Evergreen	\$2,156
4	Bridge Period	Gas Generation	Covert	Routine	Condition-based	Class 1	Approved	Long Term Service Agreement - Running capital contract	\$26,246
5	Bridge Period	Gas Generation	Covert	Routine	Condition-based	Class 2	Approved	Netmation (MHPSA Operating System & 4S) - Units 1-3	\$2,922
6	Bridge Period	Gas Generation	Covert	Routine	Condition-based	Class 4	Approved	Unit 2 - LTSA Capital - Extra work not included in contract	\$12,153
7	Bridge Period	Gas Generation	Covert	Routine	Condition-based	Class 4	Approved	Unit 3 - LTSA Capital - Extra work not included in contract	\$9,010
8	Bridge Period	Gas Generation	Jackson	Non-Routine	Condition-based	Class 3	Approved	Purchase of site spare GSU	\$1,333
9	Bridge Period	Gas Generation	Jackson	Non-Routine	Condition-based	Class 3	Approved	LM6000 ESN 191-306 HP Turbine S2 Nozzle replacement	\$1,336
10	Bridge Period	Gas Generation	Jackson	Routine	Condition-based	Class 1	Approved	GE Long Term Service Agreement FFH	\$16,200
11	Bridge Period	Gas Generation	Jackson	Routine	Condition-based	Class 1	Approved	LTSA Capital - Extra work not included in contract	\$2,115
12	Bridge Period	Gas Generation	Zeeland	Non-Routine	Condition-based	Class 1	Approved	LTSA/Phase I Gas Turbine Advanced gas path replacement and axial fuel staging	\$43,697
13	Bridge Period	Gas Generation	Zeeland	Routine	Condition-based	Class 3	Approved	LTSA - Extras not included in contract (cranes, mobile equipment)	\$4,703
14	Bridge Period	Gas Generation	Zeeland	Non-Routine	Condition-based	Class 3	Approved	Phase II Turbine Replacements	\$10,175
15	Bridge Period	Gas Generation	Zeeland	Non-Routine	Condition-based	Class 2	Approved	Purchase of Site Spare Generator Step up transformer	\$2,341
16	Bridge Period	Gas Generation	Zeeland	Non-Routine	Condition-based	Class 1	Approved	Unit 5 GSU Transformer Rewind	\$2,430
17	Bridge Period	Gas/Oil Generation	Karn 3	Non-Routine	Condition-based	Class 3	Approved	Combustion Air Heater Replacement	\$2,700
18	Bridge Period	Gas/Oil Generation	Karn 4	Non-Routine	Condition-based	Class 2	Approved	ID Fan Inlet Damper Replacements	\$2,700
19	Bridge Period	Gas/Oil Generation	Karn 4	Non-Routine	Condition-based	Class 3	Approved	Combustion Air Heater Replacement	\$3,000
20	Bridge Period	Gas/Oil Generation	Karn Commons	Non-Routine	Condition-based	Class 3	Approved	Karn 3&4 Ductwork Expansion Joint Replacement - ID Fans to Stack	\$1,800
21	Bridge Period	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Ludington 1-6 DCS Control Relay Replacement	\$2,972
22	Bridge Period	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Ludington 1 Pony Motor Overhaul	\$2,267
23	Bridge Period	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Ludington Governor Replacement	\$2,026
24	Bridge Period	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Ludington 480 Volt Motor Control Centers for DLC	\$1,288
25	Bridge Period	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Replace Lower Penstock Expansion Joint	\$2,010
26	Bridge Period	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Station Water Discharge Isolation Valve	\$1,161
27	Bridge Period	Admininstration	Admin	Non-Routine	Environmental	Class 2	Approved	Wastewater Treatment System	\$12,400
28	Bridge Period	Admininstration	Admin	Non-Routine	Infrastructure	Class 2	Approved	Lakeshore Admin Building	\$3,702
29	Bridge Period	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Class 3	Approved	Iosco Battery Energy Storage System (IRP)	\$30,053
30	Bridge Period	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Class 3	Approved	Weadock Battery Energy Storage System (IRP)	\$40,561
31	Total Bridge Period Projects								\$248,262

Consumers Energy Company

For the years 2024 through 2027

Generation Capital Expenditures

Exhibit No.: A-12 (RTB-3)

Schedule: B-5.2

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Witness: RTBlumenstock

Date: June 2025

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)		(i)
Line No.	Calendar Year	Tier 1 Portfolio	Tier 2 Portfolio	Project Type	Project Classification	Class of Cost Estimate	Full Internal Budget Approval	Work Item Description		Projected Amount
1	Test Year	Gas Generation	Covert	Non-Routine	Condition-based	Class 2	Approved	Purchase of site spare GSU		\$5,910
2	Test Year	Gas Generation	Covert	Non-Routine	Condition-based	Class 3	Approved	LCI Replacements (SFC)		\$2,610
3	Test Year	Gas Generation	Covert	Routine	Condition-based	Class 1	Approved	Long Term Service Agreement - Running capital contract		\$18,812
4	Test Year	Gas Generation	Covert	Routine	Condition-based	Class 2	Approved	Netmation (MHPSA Operating System & 4S) - Units 1-3		\$8,844
5	Test Year	Gas Generation	Covert	Routine	Condition-based	Class 4	Approved	Unit 1 - LTSA Capital - Extra work not included in contract		\$9,525
6	Test Year	Gas Generation	Covert	Routine	Condition-based	Class 4	Approved	Unit 3 - LTSA Capital - Extra work not included in contract		\$4,093
7	Test Year	Gas Generation	Jackson	Non-Routine	Condition-based	Class 3	Approved	Purchase of site spare GSU		\$2,333
8	Test Year	Gas Generation	Jackson	Routine	Condition-based	Class 1	Approved	GE Long Term Service Agreement FFH		\$12,810
9	Test Year	Gas Generation	Jackson	Routine	Condition-based	Class 3	Approved	Engine 191-306 Overhaul		\$6,130
10	Test Year	Gas Generation	Jackson	Routine	Condition-based	Class 3	Approved	Unit 7 gas turbine rotor replacement		\$1,664
11	Test Year	Gas Generation	Zeeland	Non-Routine	Condition-based	Class 1	Approved	LTSA/Phase I Gas Turbine Advanced gas path replacement and axial fuel sta		\$8,331
12	Test Year	Gas Generation	Zeeland	Non-Routine	Condition-based	Class 3	Approved	Phase II Turbine Replacements		\$10,175
13	Test Year	Gas Generation	Zeeland	Non-Routine	Condition-based	Class 2	Approved	Phase II GT Advanced gas path replacement and axial fuel staging		\$13,923
14	Test Year	Gas Generation	Zeeland	Non-Routine	Condition-based	Class 2	Approved	Purchase of Site Spare Generator Step up transformer		\$4,481
15	Test Year	Gas/Oil Generation	Karn 3	Non-Routine	Condition-based	Class 3	Approved	Combustion Air Heater Replacement		\$1,800
16	Test Year	Gas/Oil Generation	Karn 4	Non-Routine	Condition-based	Class 3	Approved	Combustion Air Heater Replacement		\$2,250
17	Test Year	Gas/Oil Generation	Karn Commons	Non-Routine	Condition-based	Class 3	Approved	Karn 3&4 Ductwork Expansion Joint Replacement - ID Fans to Stack		\$1,800
18	Test Year	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Ludington 1 Pony Motor Overhaul		\$2,800
19	Test Year	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Ludington 1-6 DCS Control Relay Replacement		\$2,907
20	Test Year	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Ludington Governor Replacement		\$2,126
21	Test Year	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Ludington 480 Volt Motor Control Centers for DLC		\$1,352
22	Test Year	Administration	Admin	Non-Routine	Environmental	Class 2	Approved	Wastewater Treatment System		\$9,600
23	Test Year	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Class 3	Approved	Iosco Battery Energy Storage System (IRP)		\$11,457
24	Test Year	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Class 3	Approved	Weadock Battery Energy Storage System (IRP)		\$14,934
25	Total Test Year Projects									\$160,668

MICHIGAN PUBLIC SERVICE COMMISSIONConsumers Energy Company

Summary of the Generation O&M Expense

For the Years 2024 through April 2027

(\$000's)

Case No.: U-21870

Exhibit No.: A-43 (RTB-4)

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Witness: RTBlumenstock

Date: June 2025

GENERATION OPERATION AND MAINTENANCE EXPENSES

Line No.	(a) Description	(b) Historical 12 Months Ended 12/31/2024		(c) Projected Bridge Period 16 Months Ending 04/30/2026		(d) Projected Test Year 12 Months Ending 04/30/2027	
1	BASE O&M	\$	91,056	\$	105,324	\$	68,705
2	ADJUSTED O&M						
3	Environmental Operations	\$	8,539	\$	5,110	\$	2,045
4	Major Maintenance	\$	28,844	\$	40,012	\$	32,982
5	Retention & Separation	\$	8,626	\$	5,182	\$	-
6	TOTAL O&M		128,438		150,445		103,732

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		2024 Actual	Base O&M for Merit & Inflation 12 Mos Ended Dec 31, 2024	Merit & Inflation 12 Mos Ending Dec 31, 2025	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2025	Merit & Inflation 12 Mos Ending Dec 31, 2026	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2026	Merit & Inflation 4 Mos Ending 4/30/2027	Other Adjustments	Projected O&M 12 Mos Ending 4/30/2027
				(c) * Inflation Rate		(e) * Inflation Rate		(g) * Inflation Rate		(b) + (d) + (f) + (h) + (i)
	Total O&M	128,438	128,438	2,697	131,136	3,147	134,283	1,074	-31,625	103,732
1	Labor	74,738	74,738	1,570	76,308	1,831	78,139	625	-18,402	60,362
2	Material	5,597	5,597	118	5,715	137	5,852	47	-1,378	4,520
3	Contractor	23,210	23,210	487	23,697	569	24,266	194	-5,715	18,745
4	Non-Labor Overheads	100	100	2	103	2	105	1	-25	81
5	Non-Labor Other	24,793	24,793	521	25,314	608	25,921	207	-6,105	20,024

Notes

	<u>2025</u>	<u>2026</u>	<u>2027</u>
* Annual merit increase			
Annual merit increase	2.10%	2.4%	2.4%
Number of months in the period	<u>12</u>	<u>12</u>	<u>4</u>
Pro-rated merit increase	2.10%	2.4%	0.8%
Annual inflation rates per WP-JCA-51			
Annual inflation rates	2.10%	2.4%	2.4%
Number of months in the period	<u>12</u>	<u>12</u>	<u>4</u>
Pro-rated inflation rate	2.10%	2.4%	0.8%

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Summary of the Generation O&M Expense

For the Years 2024 through April 2027

(\$000's)

Case No.: U-21870

Exhibit No.: A-43 (RTB-4)

Page: 3 of 3

Witness: RTBlumenstock

Date: June 2025

GENERATION MAJOR MAINTENANCE EXPENSES

Line No.	(a) Description	(b) Historical 12 Months Ended 12/31/2024		(c) Projected Bridge Period 16 Months Ending 04/30/2026		(d) Projected Test Year 12 Months Ending 04/30/2027	
	Major Maintenance						
1	Campbell 1&2	\$	903	\$	483	\$	-
2	Campbell 3	\$	591	\$	709	\$	279
3	Karn 1&2	\$	-	\$	-	\$	-
4	Karn 3&4	\$	2,027	\$	2,732	\$	1,824
5	Classic 7	\$	-	\$	291	\$	218
6	Zeeland Generating Station	\$	4,954	\$	7,063	\$	5,419
7	Jackson Generating Station	\$	5,669	\$	5,712	\$	4,112
8	Covert Generating Stations	\$	6,553	\$	8,681	\$	7,771
9	Ludington	\$	3,314	\$	5,842	\$	4,708
10	Hydros	\$	4,832	\$	7,937	\$	8,374
11	Battery	\$	-	\$	412	\$	126
12	Admin & Other	\$	-	\$	150	\$	150
13	TOTAL Major Maintenance	\$	28,844	\$	40,012	\$	32,982

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Midcontinent)
Independent System Operator)
(MISO))

Order No. 202-26-16

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 13

Kapala Direct Testimony

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of
CONSUMERS ENERGY COMPANY for approval
of an Integrated Resource Plan under
MCL 460.6t, certain accounting
approvals, and for other relief.

Case No. U-21090

Volume 7

PUBLIC RECORD

CROSS-EXAMINATION

Proceedings held via Microsoft Teams in the
above-entitled matter before Sally L. Wallace,
Administrative Law Judge with MOAHR, for the Michigan
Public Service Commission, Lansing, Michigan, on
Tuesday, December 7, 2021, at 10:07 a.m.

APPEARANCES:

ROBERT W. BEACH, ESQ.
BRET A. TOTORAITIS, ESQ.
THERESA A.G. STALEY, ESQ.
MICHAEL C. RAMPE, ESQ.
GARY A. GENSCH, JR., ESQ.
ANNE M. UITVLUGT, ESQ.
IAN F. BURGESS, ESQ.
Consumers Energy Company
One Energy Plaza, Room EP11-223
Jackson, Michigan 49201

On behalf of Consumers Energy Company

(Continued)

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STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of an Integrated Resource Plan	)	Case No. U-21090
under MCL 460.6t, certain accounting	)	
approvals, and for other relief.	)	
_____	)	

REVISED DIRECT TESTIMONY

OF

NORMAN J. KAPALA

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2021

NORMAN J. KAPALA
REVISED DIRECT TESTIMONY

1 **Q. Please state your name and business address.**

2 A. My name is Norman J. Kapala, and my business address is One Energy Plaza, Jackson,
3 Michigan 49201.

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

5 A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”)
6 as Executive Director of Fossil and Renewable Generation.

7 **Q. What is your formal education experience?**

8 A. In 1996, I received a Bachelor of Science in Mechanical Engineering from Michigan
9 Technological University. In 2008, I received a Master of Science in Manufacturing
10 Management from Kettering University.

11 **Q. Please describe your business experience.**

12 A. From 1990 to 1994, I served our country as a Rifleman in the United States Marine Corps.
13 In May 1996, I joined Chrysler Corporation and held various positions with progressing
14 levels of responsibility at the Trenton Engine Plant, progressing from a Technical Advisor
15 to Area Manager. In September 2002, I joined Delphi Corporation as a Production
16 Supervisor and, in September 2004, progressed to a Senior Manufacturing Engineer. In
17 July 2008, I joined Consumers Energy at the D.E. Karn (“Karn”)/ J.C. Weadock
18 (“Weadock”) Generating Complex and progressed through positions from Senior Engineer
19 to the Site Business Manager. In June 2015, I transferred to the B.C. Cobb (“Cobb”)
20 Generating Complex and J.H. Campbell (“Campbell”) Generating Complex as the Site
21 Business Manager for both facilities. Following the closure of seven of the Company’s
22 coal-fired units at its Cobb, Weadock, and J.R. Whiting (“Whiting”) sites (collectively, the
23 “Classic 7”) in 2016, I was promoted to Executive Director of Coal Generation. In April

NORMAN J. KAPALA
REVISED DIRECT TESTIMONY

2020, I was appointed to the position of Executive Director of Fossil and Renewable Generation with operations and maintenance responsibility for Coal, Gas, Wind, and Solar Generation.

Q. Have you previously sponsored testimony before the Michigan Public Service Commission (“MPSC” or the “Commission”)?

A. Yes. I sponsored testimony in the following MPSC cases:

Case No. U-20165	2018 Integrated Resource Plan under MCL 460.6t;
Case No. U-20202	2018 Power Supply Cost Recovery (“PSCR”) Reconciliation;
Case No. U-20219	2019 PSCR Plan;
Case No. U-20220	2019 PSCR Reconciliation;
Case No. U-20525	2020 PSCR Plan;
Case No. U-20844	Ludington Depreciation Case;
Case No. U-20802	2021 PSCR Plan; and
Case No. U-20526	2020 PSCR Reconciliation.

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

A. My direct testimony will address: (i) a description of Consumers Energy’s existing generation resources; (ii) the Company’s projected capital expenditures and Operations and Maintenance (“O&M”) expenses for its existing generation fleet, as those costs were represented in Consumers Energy’s Integrated Resource Plan (“IRP”) modeling; (iii) the Company’s projected capital expenditures and O&M expenses for the Covert combined cycle gas plant (“Covert”), the Dearborn Industrial Generation combined cycle and peaking units (“DIG”), the Kalamazoo River Generating Station peaking plant (“Kalamazoo”), and the Livingston Generating Station peaking plant (“Livingston”) that are included in the Company’s Proposed Course of Action (“PCA”); (iv) the Company’s projected separation

NORMAN J. KAPALA
REVISED DIRECT TESTIMONY

activity costs related to the early retirement of its existing generating units at the Campbell and Karn generating sites; (v) Consumers Energy's avoidable and incremental capital expenditures and expenses in different cases involving the early retirement of Campbell Units 1 and 2, Campbell Unit 3, and Karn Units 3 and 4; (vi) the performance of the Company's existing generation fleet; (vii) execution risks faced by Consumers Energy if Campbell Units 1, 2, or 1 and 2, Campbell Unit 3, or Karn Units 3 and 4 are selected for early retirement; and (viii) the tax, community, and employee impacts of an early retirement case.

Q. What is the Company's retirement recommendation with respect to Campbell Units 1 and 2, Campbell Unit 3, and Karn Units 3 and 4?

A. As discussed by several Company witnesses, and as also further explained in my direct testimony, Consumers Energy's PCA proposes to retire Karn Units 3 and 4 in 2023, and retire Campbell Units 1, 2, and 3 in 2025. As discussed in Section II of my testimony, this PCA will result in \$75,648,000 in avoided capital expenditures, \$15,645,00 in avoided unit separation capital expenditures, and \$10,050,000 in avoided major maintenance expenses at Karn Units 3 and 4 compared to the Company's base case outlook ("base case"). In addition, this PCA will result in ~~\$190,613,000~~\$136,244,000 in avoided capital expenditures, \$64,146,000 in avoided unit separation capital expenditures, and \$57,555,000 in avoided major maintenance expenses at Campbell Unit 3; \$12,114,000 in avoided capital expenditures and \$61,524,000 in avoided major maintenance expenses at Campbell Unit 1; and \$13,385,000 in avoided capital expenditures and \$84,186,000 in avoided major maintenance expenses at Campbell Unit 2, compared to the Company's base case

NORMAN J. KAPALA
REVISED DIRECT TESTIMONY

assumptions of continued operations to the units current design lives in each of the scenarios described by Company witness Sara T. Walz.

Q. Are there any offsets to the avoided cost numbers?

A. Yes. The avoided capital expenditures, avoided unit separation capital expenditures, and avoided major maintenance expenses would be partially offset by the capital expenditures and O&M expenses for the Covert, DIG, Kalamazoo, and Livingston gas generating plants (collectively “new gas plants”) which are discussed in Section III of my direct testimony. The Company is also projecting that it will incur approximately \$60,000,000 in employee retention and separation activity expenses, as discussed in Section VIII of my direct testimony; however, the Company does not consider these costs incremental in nature as the Company would have incurred these costs at a later date had an early retirement not occurred.

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

A. Yes. I am sponsoring the following exhibits:

Exhibit A-50 (NJK-1) <u>Revised</u>	Summary of Capital Expenditures and Operations and Maintenance Expenses;
Exhibit A-51 (NJK-2) <u>Revised</u>	Summary of Projected Generation Operations Capital Expenditures;
Exhibit A-52 (NJK-3)	Summary of Projected Generation Operations Major Maintenance Expenses;
Exhibit A-53 (NJK-4)	Summary of Projected Generation Operations Base O&M Expenses;
Exhibit A-54 (NJK-5)	Generation Operations – Summary of Capital Expenditures and Costs of Removal;

NORMAN J. KAPALA
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1	Exhibit A-55 (NJK-6) <u>Revised</u>	Summary of Projected Generation
2		Operations Capital Expenditures and
3		Operations and Maintenance
4		Expenses – new gas plants;
5	Exhibit A-56 (NJK-7)	Summary of Projected Generation
6		Operations Separation Activity
7		Capital Expenditures;
8	Exhibit A-57 (NJK-8) <u>Revised</u>	Generation Capital Expenses –
9		Avoidable And Incremental Under
10		an Early Retirement Case 2024 -
11		2032;
12	Exhibit A-58 (NJK-9)	Generation Major Maintenance
13		Expenses – Avoidable Under An
14		Early Retirement Case 2024-2032;
15	Exhibit A-59 (NJK-10)	Generating Unit Random Outage
16		Rates; and
17	Confidential Exhibit A-60 (NJK-11)	Generating Unit Heat Rates.

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

A. Yes.

NORMAN J. KAPALA
REVISED DIRECT TESTIMONY

SECTION I: EXISTING GENERATION RESOURCES

Q. Please provide an overview of the Company's non-renewable energy generation assets.

A. As of 2020, the Company's total non-renewable owned generation assets had a net demonstrated summer operating capability of 5,292 MW, comprised of the following coal-, oil-, or gas-fired; hydroelectric; and pumped storage facility units:

TABLE 1

RESOURCE	MICHIGAN LOCATION	IN-SERVICE DATE	AGE (years)	RETIREMENT DATE	REMAINING EST. TIME OF OPERATION (years)	LICENSING STATUS	NET GENERATING CAPABILITY (MW)
COAL FIRED							
JH Campbell 1	West Olive, MI	1962	59	2031	10	Active	260
JH Campbell 2	West Olive, MI	1967	54	2031	10	Active	260
JH Campbell 3	West Olive, MI	1980	41	2039	18	Active	785 (owned share)
DE Karn 1	Essexville, MI	1959	62	2023	2	Active	255
DE Karn 2	Essexville, MI	1961	60	2023	2	Active	258
OIL OR GAS FIRED							
DE Karn 3	Essexville, MI	1975	46	2031	10	Active	362
DE Karn 4	Essexville, MI	1977	44	2031	10	Active	362
Zeeland CC	Zeeland, MI	2002	19	2041	20	Active	575
Zeeland 1A	Zeeland, MI	2002	19	2041	20	Active	180
Zeeland 1B	Zeeland, MI	2002	19	2041	20	Active	180
Jackson	Jackson, MI	2002	19	2041	20	Active	547
HYDROELECTRIC							
Alcona	Alcona County, MI	1924	97	n/a	n/a	Active	8
Allegan	Allegan County, MI	1936	85	n/a	n/a	Active	3
Cooke	Iosco County, MI	1911	110	n/a	n/a	Active	9
Croton	Newaygo County, MI	1907	114	n/a	n/a	Active	9
Five Channels	Iosco County, MI	1912	109	n/a	n/a	Active	6
Footte	Iosco County, MI	1918	103	n/a	n/a	Active	9
Hardy	Newaygo County, MI	1931	90	n/a	n/a	Active	30
Hodenpyl	Wexford County, MI	1925	96	n/a	n/a	Active	17
Loud	Iosco County, MI	1913	108	n/a	n/a	Active	4
Mio	Oscoda County, MI	1916	105	n/a	n/a	Active	5
Rogers	Mecosta County, MI	1906	115	n/a	n/a	Active	7
Tippy	Manistee County, MI	1918	103	n/a	n/a	Active	21
Webber	Ionia County, MI	1907	114	n/a	n/a	Active	3
ENERGY STORAGE							
Ludington Units 1-6	Ludington, MI	1973	48	2069	48	Active	1138 (owned share)

Q. What does "owned share" mean when used with respect to Campbell Unit 3?

A. The Company owns approximately 93% of Campbell Unit 3. Michigan Public Power Agency and Wolverine Power Supply Cooperative, Inc. own the remaining 7%. Thus, the 785 MW capacity reported is 93% of the Campbell Unit 3 net demonstrated summer operating capability, reflecting the Company's share of ownership.

NORMAN J. KAPALA
REVISED DIRECT TESTIMONY

1 **Q. What does “owned share” mean when used with respect to Ludington Pumped**
 2 **Storage Plant (“Ludington” or the “Ludington Plant”) Units 1-6?**

3 A. The Company owns 51% of the Ludington Plant and DTE Electric Company owns the
 4 remaining 49%. Thus, the 1,138 MW capacity reported is 51% of the total Ludington Plant
 5 net demonstrated summer operating capability, reflecting the Company’s share of
 6 ownership.

7 **SECTION II: PROJECTED CAPITAL EXPENDITURES AND O&M EXPENSES**
 8 **OF EXISTING GENERATION FLEET**

9 **Q. Please explain Exhibit A-50 (NJK-1) Revised.**

10 A. Exhibit A-50 (NJK-1) Revised shows the projected capital expenditures and major
 11 maintenance expenses for the Campbell Units 1, 2, and 3; Karn Units 1 and 2; and Karn
 12 Units 3 and 4 for the period of January 1, 2020 through May 31, 2031, and the base O&M
 13 expenses for the Campbell Units 1, 2, and 3; Karn Units 1 and 2; and Karn Units 3 and 4
 14 for the same period, under a variety of cases. These are the costs and the date range that
 15 the Company used for modeling purposes in this IRP. The Company evaluated a base case,
 16 in which all four units (Karn Units 3 and 4 and Campbell Units 1 and 2) retire on May 31,
 17 2031, and then evaluated sixteen early retirement cases related to the Karn and Campbell
 18 sites:

- 19 • Retirement of Karn Units 3 and 4 on May 31, 2023;
- 20 • Retirement of Karn Units 3 and 4 on May 31, 2025;
- 21 • Retirement of Campbell Unit 3 on May 31, 2025;
- 22 • Retirement of Campbell Unit 3 on May 31, 2032;
- 23 • Retirement of Campbell Unit 1 on May 31, 2024;
- 24 • Retirement of Campbell Unit 1 on May 31, 2025;

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- Retirement of Campbell Unit 1 on May 31, 2026;
- Retirement of Campbell Unit 1 on May 31, 2028;
- Retirement of Campbell Unit 2 on May 31, 2024;
- Retirement of Campbell Unit 2 on May 31, 2025;
- Retirement of Campbell Unit 2 on May 31, 2026;
- Retirement of Campbell Unit 2 on May 31, 2028;
- Retirement of Campbell Units 1 and 2 on May 31, 2024;
- Retirement of Campbell Units 1 and 2 on May 31, 2025;
- Retirement of Campbell Units 1 and 2 on May 31, 2026; and
- Retirement of Campbell Units 1 and 2 on May 31, 2028.

Q. Please explain Exhibit A-50 (NJK-1) Revised, pages 1 and 2.

A. Exhibit A-50 (NJK-1) Revised, pages 1 and 2, presents the total capital expenditures projected to be made at the Karn and Campbell sites by the Company in each of the sixteen cases listed above. With the exception of Campbell Unit 3, the capital expenditure amounts presented for each unit in each case is a total of all capital expenditures for the period of January 1, 2020 through May 31, 2031. The capital expenditure amounts for Campbell Unit 3 reflect projected amounts through May 31, 2039. For each of the sixteen early retirement cases, the exhibit presents both the total capital expenditures (including unit separation) over that period that would be made in each respective case and the difference in capital expenditures over that period relative to the base case. Exhibit A-50 (NJK-1) Revised, page 1, lines 2 and 3 reflects the early retirement cases for Karn Units 3 and 4; for these cases, the capital expenditures for Karn Units 3 and 4 are reduced versus those shown in the base case. As shown in Exhibit A-50 (NJK-1) Revised, page 1, lines 2 and

NORMAN J. KAPALA
REVISED DIRECT TESTIMONY

3, columns (b) and (c), the 2023 retirement case results in both reduced capital expenditures and also reduced separation costs at Karn Units 3 and 4, and the 2025 retirement case results in reduced capital expenditures at Karn Units 3 and 4, which will be discussed later in my direct testimony. Likewise, Exhibit A-50 (NJK-1) Revised, page 1, lines 4 and 5, reflects the early retirement cases for Campbell Unit 3; for each of these cases, both the capital expenditures and separation costs for Campbell Unit 3 are also reduced from those shown in the base case. Exhibit A-50 (NJK-1) Revised, pages 1-2, lines 6 through 17, reflects the retirement cases for which Campbell Unit 1 retires, Campbell Unit 2 retires, or both Campbell Units 1 and 2 retire. Exhibit A-50 (NJK-1) Revised, pages 1 and 2, lines 6 through 13, columns (c) and (d), shows the reduced or incremental costs for Campbell Units 1 and 2 versus the base case for the individual unit retirements. Exhibit A-50 (NJK-1) Revised, page 2, lines 14 through 17, columns (c) and (d), show reduced costs at Campbell Units 1 and 2 when both units retire. No incremental costs are projected at Campbell Unit 3 versus the base case for the cases in which Campbell Units 1 and 2 both retire. Costs of removal are not included in any of the cases in Exhibit A-50 (NJK-1) Revised, page 1, nor are environmental costs related to Steam Electric Effluent Guidelines (“SEEG”) and Clean Water Act Section 316(b) (“316(b)”). Those environmental costs are discussed by Company witness Heather A. Breining.

Q. Please explain Exhibit A-50 (NJK-1) Revised, pages 3 and 4.

A. Exhibit A-50 (NJK-1) Revised, pages 3 and 4, presents the total major maintenance expenses projected to be made at the Karn and Campbell sites by the Company in each of the sixteen cases listed above. With the exception of Campbell Unit 3, the major maintenance expenses presented for each unit in each case is a total of all major

NORMAN J. KAPALA
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1 maintenance expenses for the period of January 1, 2020 through May 31, 2031. The major
2 maintenance expenses for Campbell Unit 3 reflect projected amounts through May 31,
3 2039. For each of the 16 early retirement cases, the exhibit presents both the total major
4 maintenance expenses over that period that would be made in each respective case, and the
5 difference in major maintenance expenses over that period relative to the base case. Exhibit
6 A-50 (NJK-1) **Revised**, page 3, lines 2 and 3, reflects the early retirement cases for Karn
7 Units 3 and 4; for these cases, the major maintenance expenses for Karn Units 3 and 4 are
8 reduced from those shown in the base case. Likewise, Exhibit A-50 (NJK-1) **Revised**, page
9 3, lines 4 and 5, reflects the early retirement cases for Campbell Unit 3; for each of these
10 cases, the major maintenance expenses for Campbell Unit 3 are also reduced from those
11 shown in the base case. Exhibit A-50 (NJK-1) **Revised**, pages 3 and 4, lines 6 through 17,
12 reflects the retirement cases for which Campbell Unit 1 retires, Campbell Unit 2 retires, or
13 both Campbell Units 1 and 2 retire. Exhibit A-50 (NJK-1) **Revised**, pages 3 and 4, lines 6
14 through 13, columns (c) and (d), shows the reduced major maintenance expenses for
15 Campbell Units 1 and 2 versus the base case for the individual unit retirements. Exhibit
16 A-50 (NJK-1) **Revised**, page 2, lines 14 through 17 columns (c) and (d), shows reduced
17 costs at Campbell Units 1 and 2 when both units retire. No incremental major maintenance
18 expenses are projected at Campbell Unit 3 versus the base case for the cases in which
19 Campbell Units 1 and 2 both retire. Exhibit A-50 (NJK-1) **Revised**, pages 3 and 4, does
20 not include environmental costs related to SEEG and Clean Water Act Section 316(b)
21 (“316(b)”). Those environmental costs are discussed by Company witness Breining.

22 **Q. Please explain Exhibit A-50 (NJK-1) **Revised**, pages 5 and 6.**

NORMAN J. KAPALA
REVISED DIRECT TESTIMONY

1 A. Exhibit A-50 (NJK-1) Revised, pages 5 and 6, presents the total O&M expenses projected
2 to be made at the Karn and Campbell sites by the Company in each of the sixteen cases
3 listed above. With the exception of Campbell Unit 3, the O&M expenses presented for
4 each unit in each case is a total of all O&M expenses for the period of January 1, 2020
5 through May 31, 2031. The O&M expenses for Campbell Unit 3 reflect projected amounts
6 through May 31, 2039. For each of the 16 early retirement cases, the exhibit presents both
7 the total O&M expenses over that period that would be made in each respective case and
8 the difference in O&M expenses over that period relative to the base case. Exhibit A-50
9 (NJK-1) Revised, page 5, lines 2 and 3, reflects the early retirement cases for Karn Units 3
10 and 4; for these cases, the O&M expenses for Karn Units 3 and 4 are reduced from those
11 shown in the base case. Likewise, Exhibit A-50 (NJK-1) Revised, page 5, lines 4 and 5,
12 reflects the early retirement cases for Campbell Unit 3; for each of these cases, the O&M
13 expenses for Campbell Unit 3 are also reduced from those shown in the base case. Exhibit
14 A-50 (NJK-1) Revised, pages 5 and 6, lines 6 through 17, reflects the retirement cases for
15 which Campbell Unit 1 retires, Campbell Unit 2 retires, or both Campbell Units 1 and 2
16 retire. Exhibit A-50 (NJK-1) Revised, pages 5 and 6, lines 6 through 9, columns (c), (d),
17 and (e), shows the reduced O&M expenses for Campbell Unit 1 retirement and increased
18 O&M expenses for Campbell Units 2 and 3 versus the base case for the individual unit
19 retirements. Exhibit A-50 (NJK-1) Revised, pages 5 and 6, lines 10 through 13, columns
20 (c), (d), and (e), shows the reduced O&M expenses for Campbell Unit 2 retirement and
21 increased O&M expenses for Campbell Units 1 and 3 versus the base case for the individual
22 unit retirements. Exhibit A-50 (NJK-1) Revised, page 2, lines 14 through 17, columns (c),
23 (d), and (e), shows the reduced O&M expenses for Campbell Units 1 and 2 when both units

NORMAN J. KAPALA
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1 retire and increased O&M expenses for Campbell Unit 3. Exhibit A-50 (NJK-1) Revised,
 2 pages 5 and 6 do not include environmental costs related to SEEGand Clean Water Act
 3 Section 316(b) (“316(b)”). Those environmental costs are discussed by Company witness
 4 Breining.

5 **Q. Please explain Exhibit A-51 (NJK-2) Revised, page 1.**

6 A. Exhibit A-51 (NJK-2) Revised, page 1, shows the Company’s projected capital
 7 expenditures for the Company’s generating units at the Campbell and Karn sites for each
 8 calendar year over the period from January 1, 2020 through May 31, 2039 in the base case
 9 retirement case. In this case, Karn Units 1 and 2 retire on May 31, 2023, Karn Units 3 and
 10 4 and Campbell Units 1 and 2 retire on May 31, 2031, and Campbell Unit 3 retires on May
 11 31, 2039.

12 **Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2)**
 13 **Revised, page 1, line 1?**

14 A. The capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 1, are those that
 15 were used for 2020 in the Company’s IRP modeling.

16 **Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2)**
 17 **Revised, page 1, line 2?**

18 A. In 2021, the Company projects to spend:

- 19 • \$2,859,236 at Karn Units 1 and 2, covering seventeen projects, none of which
 20 exceed \$500,000;
- 21 • \$4,172,000 at Karn Units 3 and 4, including:
 - 22 o Auxiliary Boiler System Optimization (\$2,000,000);
 - 23 o Replace House Service Water Screen Drives (\$950,000); and
 - 24 o Twenty-seven additional projects totaling \$1,222,000, with no individual
 25 project exceeding \$300,000;

NORMAN J. KAPALA
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- \$3,493,440 at Campbell Unit 1, including:
 - o Re-align 4160V switchgear with Air Quality Control System (“AQCS”) implementation (\$1,000,000); and
 - o Eleven additional projects totaling \$2,493,440, with no individual project exceeding \$696,000;
- \$13,512,160 at Campbell Unit 2, including:
 - o Low Pressure Turbine Overhaul (\$3,500,000);
 - o Secondary Air Heater Basket and Seal Replacement (\$1,750,000);
 - o Pulse Jet Fabric Filter (“PJFF”) Bag Replacement (\$2,394,000); and
 - o Seventeen additional projects totaling \$5,868,160, with no individual project exceeding \$858,100; and
- \$19,576,382 at Campbell Unit 3, including:
 - o Selective Catalytic Reduction (“SCR”) Reactor Catalyst Management (\$1,959,510);
 - o Replace CO-O2 Monitors (\$1,044,600);
 - o Mill Complete Overhauls (\$1,235,000);
 - o Reheater Sootblower (\$1,250,000);
 - o Sootblowing Air Upgrade (\$1,200,000);
 - o Replace Lake Michigan Intake Screens (\$1,339,000);
 - o Cell Construction and Permitting (\$5,482,830); and
 - o Twenty-two additional projects totaling \$6,06,442, with no individual project exceeding \$750,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2)

Revised, page 1, line 3?

A. In 2022, the Company projects to spend

- \$2,135,136 at Karn Units 1 and 2, covering 12 projects, none of which exceeds \$350,000;

NORMAN J. KAPALA
REVISED DIRECT TESTIMONY

- \$15,416,000 at Karn Units 3 and 4, including:
 - o Tank Farm Storage Tank Heating Lines (\$1,400,000);
 - o Karn Sync Wire Replacement (\$1,320,000);
 - o Auxiliary Boiler System Optimization (\$1,160,000);
 - o Parking Lot Replacement (\$1,000,000);
 - o Karn 3 Ductwork Expansion Joint Replacement (\$3,000,000);
 - o Karn 3 Cooling Tower Rebuild (\$2,500,000); and
 - o Twenty-two additional projects totaling \$5,036,000, with no individual project exceeding \$450,000;
- \$7,300,000 at Campbell Unit 1, including:
 - o PJFF Bag Replacement (\$1,578,000);
 - o Superheat Outlet Pendant – partial replacement (\$3,490,000); and
 - o Five additional projects totaling \$2,232,000, with no individual project exceeding \$750,000;
- \$5,256,500 at Campbell Unit 2, including:
 - o Catalyst Management (\$1,120,000);
 - o Replace Burner Assemblies (\$1,350,000); and
 - o Six additional projects totaling \$2,786,500, with no individual project exceeding \$836,500; and
- \$17,125,333 at Campbell Unit 3, including:
 - o PJFF Bag & Cleaning Air Manifold Replacement (\$3,994,601);
 - o SCR Reactor Catalyst Management (\$1,866,200);
 - o Complete Mill Overhauls (\$1,264,800);
 - o Replace CO-O2 Monitors (\$967,400);
 - o Design and Install New Large Particle Ash Screen (\$1,485,100);
 - o Fuel Handling & Infrastructure Repairs (\$1,500,000); and

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- o Sixteen additional projects totaling \$6,047,032, with no individual project exceeding \$889,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2)

Revised, page 1, line 4?

A. In 2023, the Company projects to spend:

- \$1,123,678 at Karn Units 1 and 2, covering 12 projects, none of which exceeds \$235,136;
- \$10,072,000 at Karn Units 3 and 4, including:
 - o Distributed Control System Evergreen Project (\$1,000,000);
 - o Karn 3 Ductwork Expansion Joint Replacement (\$1,000,000);
 - o Karn 3 Cooling Tower Rebuild (\$4,800,000);
 - o Capital Equipment Repairs (\$1,000,000); and
 - o Twelve additional projects totaling \$2,272,000, with no individual project exceeding \$758,000;
- \$7,214,680 at Campbell Unit 1, including:
 - o PJFF Filter Bag Replacement (\$1,514,100);
 - o Replace Air Preheater Baskets and Seals (\$1,113,400);
 - o Distributed Control System and Simulator Upgrade (\$1,500,000);
 - o Ashpit Rebuild (\$1,000,000); and
 - o Twelve additional projects totaling \$2,087,180, with no individual project exceeding \$750,000;
- \$9,472,020 at Campbell Unit 2, including:
 - o Horizontal Reheat Replacement (\$5,053,000);
 - o SCR Reactor Catalyst Replacement (\$2,000,000); and
 - o Nine additional projects totaling \$2,419,020, with no individual project exceeding \$750,000; and
- ~~\$20,766,757~~\$20,478,187 at Campbell Unit 3, including:

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- o PJFF Bag & Cleaning Air Manifold Replacement (\$3,263,331);
- o Complete Mill Overhauls (\$1,295,300);
- o Design and Install New Large Particle Ash Screen (\$1,008,700);
- o Secondary Air Heater basket & seal replacement (\$2,425,000)
- o High Pressure Feedwater Heater 8A replacement (\$5,039,800);
- o Fuel Handling & Infrastructure Repairs (\$1,500,000); and
- o ~~Eighteen-Seventeen~~ additional projects totaling ~~\$7,242,827~~\$6,954,257, with no individual project exceeding \$750,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2)

Revised, page 1, line 5?

A. In 2024, the Company projects to spend:

- \$9,775,000 at Karn Units 3 and 4, including:
 - o Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack (\$800,000);
 - o Karn 3 Cooling Tower Rebuild (\$4,950,000);
 - o Capital Equipment Repairs (\$3,000,000); and
 - o Twelve additional projects totaling \$2,272,000, with no individual project exceeding \$758,000;
- \$9,753,000 at Campbell Unit 1 including:
 - o Replace Burners Corner 1-8 (\$2,700,000);
 - o Replace Air Preheater Baskets and Seals (\$1,137,100);
 - o Boiler Component Replacement (\$3,000,000);
 - o Balance of Plant Equipment Replacement (\$1,500,000) and
 - o Six additional projects totaling \$1,415,900, with no individual project exceeding \$815,900;
- \$11,252,000 at Campbell Unit 2, including:
 - o Horizontal Reheat Replacement (\$7,952,000);

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- o Distributed Control System and Simulator Upgrade (\$1,500,000); and
- o Four additional projects totaling \$1,800,000, with no individual project exceeding \$750,000; and
- ~~\$35,780,799~~33,395,569 at Campbell Unit 3, including:
 - o SCR Reactor Catalyst Management (\$1,959,510);
 - o Turbine Drain Modifications (\$2,535,000);
 - o Superheat Terminal Drain Replacement (\$3,023,100);
 - o Replace Boiler Sidewall Panels (\$2,425,000);
 - o Replace Boiler Front And Rear Wall Panels (\$2,482,900);
 - o Secondary Air Heater basket & seal replacement (\$1,562,000);
 - o Fuel Handling & Infrastructure Repairs (\$1,500,000);
 - ~~o Dry Ash Landfill Closure (\$1,635,230);~~
 - o Cell Construction and Permitting (\$5,482,830); and
 - o ~~Twenty-two~~Twenty-one additional projects totaling ~~\$10,600,029~~12,425,229, with no individual project exceeding \$933,100.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2)

Revised, page 1, line 6?

A. In 2025, the Company projects to spend:

- \$10,134,000 at Karn Units 3 and 4, including:
 - o Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack (\$2,500,000);
 - o Karn 3 Cooling Tower Rebuild (\$2,565,000);
 - o Capital Replacements (\$4,000,000); and
 - o Three additional projects totaling \$1,069,000, with no individual project exceeding \$750,000;
- \$2,550,000 at Campbell Unit 1, including four projects that do not exceed \$669,000 individually; and

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- \$7,800,000 at Campbell Unit 2, including:
 - Replace turbine right side Reheat Stop Valve body (\$1,850,000); and
 - Boiler Component Replacement (\$3,000,000);
- Five additional projects totaling \$2,950,000, with no individual project exceeding \$750,000; and
- ~~\$30,179,045~~ \$14,512,045 at Campbell Unit 3, including:
 - GSU Replacement (\$6,485,045);
 - SCR Reactor Catalyst Management (\$3,000,000);
 - AQCS Equipment repair/replacement (\$1,000,000);
 - ~~Part 115 JH Campbell B-K landfill cap (\$15,667,000)~~
 - Cell Construction and Permitting (\$2,000,000); and
 - Four additional projects totaling \$2,027,000, with no individual project exceeding \$750,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2)

Revised, page 1, line 7?

A. In 2026, the Company projects to spend:

- \$9,900,000 at Karn Units 3 and 4, including:
 - Karn 3 Ductwork Replace Insulation & Lagging - ID Fan to Stack (\$4,000,000);
 - Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack (\$3,000,000);
 - Capital Replacements (\$2,000,000); and
 - Three additional projects totaling \$6,050,000, with no individual project exceeding \$250,000;
- \$3,300,000 at Campbell Unit 1, including five projects that do not exceed \$750,000 individually;
- \$4,420,000 at Campbell Unit 2, including:

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- o Catalyst Management (\$1,120,000); and
- o Five additional projects totaling \$3,300,000, with no individual project exceeding \$750,000; and
- ~~\$29,053,000~~\$4,400,000 at Campbell Unit 3, including:
 - ~~o Replace Air and Flue Gas Expansion Joints (\$2,000,000);~~
 - o ~~Part 115 JH Campbell B-K landfill cap (\$24,653,000);~~ and
 - o Four additional projects totaling \$2,400,000, with no individual project exceeding \$750,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, lines 8 through 20?

A. In each year from 2027 through 2039 in the base case, the Company projects to incur capital expenditures at Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3, as shown in Exhibit A-51 (NJK-2) Revised, page 1. The capital projects for Karn Units 3 and 4 are as follows:

- 2027: Four projects totaling \$8,950,000, which includes:
 - o K3 Ductwork Replace Insulation & Lagging - ID Fan to Stack (\$2,600,000);
 - o Karn 3 Distributed Control System (“DCS”) & Simulator Evergreen (\$1,000,000);
 - o Karn 4 DCS & Simulator Evergreen (\$1,350,000); and
 - o Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack (\$4,000,000);
- 2028-2029: One project each year totaling \$2,000,000, for capital replacements;
- 2030: One project totaling \$1,000,000, for capital replacements; and
- 2031: One project totaling \$500,000, for capital replacements.

The capital projects for Campbell Unit 1 are as follows:

- 2027: Five projects totaling \$4,050,000, which include:

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- o DCS and Simulator Upgrade (\$1,500,000); and
- o Four additional projects totaling \$2,550,000, with no individual project exceeding \$750,000;
- 2028: Four projects totaling \$3,500,000, which include:
 - o Fuel Handling and Infrastructure Replacements (\$1,000,000);
 - o AQCS Equipment Repair/Replacement (\$1,000,000); and
 - o Two additional projects totaling \$1,500,000, with no individual project exceeding \$750,000;
- 2029: Five projects totaling \$3,878,000, which includes:
 - o PJFF Filter Bag Replacement (\$1,578,000);
 - o AQCS Equipment repair/replacement (\$1,000,000); and
 - o Three additional projects totaling \$1,300,000, with no individual project exceeding \$500,000;
- 2030: Five projects totaling \$2,563,000, which include:
 - o PJFF Filter Bag Replacement (\$1,513,600); and
 - o Four additional projects totaling \$1,050,000, with no individual project exceeding \$300,000; and
- 2031: One Project totaling \$250,000.

The capital projects for Campbell Unit 2 are as follows:

- 2027: Eight projects totaling \$6,845,000, which include:
 - o Catalyst Management (\$2,806,000);
 - o PJFF bag replacement (\$1,389,000); and
 - o Six projects totaling \$2,650,000 with no individual project which exceeds \$750,000;
- 2028: Six projects totaling \$7,394,000, which include:
 - o DCS and Simulator Upgrade (\$1,500,000);
 - o PJFF bag replacement (\$1,389,000);

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- o Fuel Handling and Infrastructure Replacements (\$1,000,000);
- o AQCS Equipment repair/replacement (\$1,000,000); and
- o Two projects totaling \$1,500,000 with no individual project which exceeds \$500,000;
- 2029: Five projects totaling \$2,500,000, which include;
 - o AQCS Equipment repair/replacement (\$1,000,000); and
 - o Four projects totaling \$1,894,333 with no individual project which exceeds \$500,000;
- 2030: Four projects totaling \$1,050,000, with no individual project which exceeds \$300,000; and
- 2031: One project totaling \$250,000.

The capital projects for Campbell Unit 3 are as follows:

- 2027: ~~Six~~ Five projects totaling ~~\$30,563,600~~ \$5,900,000, including:
 - o ~~Cell Construction and Permitting (\$3,500,000);~~
 - o ~~Part 115 JH Campbell B-K landfill cap (\$24,663,000);~~ and
 - o Four additional projects totaling \$2,400,000, with no individual project exceeding \$750,000;
- 2028: Five projects totaling \$4,400,000, including:
 - o SCR Reactor Catalyst Management (\$2,000,000); and
 - o Four additional projects totaling \$2,400,000, with no individual project exceeding \$750,000;
- 2029: Six projects totaling \$11,750,000, which include:
 - o SCR Reactor Catalyst Management (\$3,000,000);
 - o Boiler Component Replacement (\$5,000,000);
 - o AQCS Equipment repair/replacement (\$2,000,000); and
 - o Three additional projects totaling \$1,750,000, with no individual project exceeding \$750,000;

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- 1 • 2030: ~~Four~~ Five projects totaling ~~\$4,650,000~~ \$11,150,000, which include:
 - 2 o SCR Reactor Catalyst Management (\$3,000,000);
 - 3 o Cell Construction and Permitting (\$6,500,000);
 - 4 o AQCS Equipment repair/replacement (\$3,000,000); and
 - 5 o Three additional projects totaling \$1,650,000, with no individual project
 - 6 exceeding \$750,000;
- 7 • 2031: Four projects totaling \$2,400,000, with no individual project which
- 8 exceeds \$750,000;
- 9 • 2032: Four projects totaling \$2,750,000, which include:
 - 10 o AQCS Equipment repair/replacement (\$1,000,000); and
 - 11 o Three additional projects totaling \$1,750,000, with no individual project
 - 12 exceeding \$750,000;
- 13 • 2033: Seven projects totaling \$11,750,000, which include:
 - 14 o SCR Reactor Catalyst Management (\$2,000,000);
 - 15 o Replace Air and Flue Gas Expansion Joints (\$2,000,000);
 - 16 o Boiler Component Replacement (\$5,000,000);
 - 17 o AQCS Equipment Repair/Replacement (\$1,000,000); and
 - 18 o Three additional projects totaling \$1,750,000, with no individual project
 - 19 exceeding \$750,000;
- 20 • 2034: Five projects totaling \$5,400,000, which include:
 - 21 o SCR Reactor Catalyst Management (\$3,000,000); and
 - 22 o Four additional projects totaling \$2,400,000, with no individual project
 - 23 exceeding \$750,000;
- 24 • 2035: ~~Five~~ Four projects totaling ~~\$3,650,000~~ \$10,150,000, which include:
 - 25 o AQCS Equipment repair/replacement (\$2,000,000);
 - 26 o Cell Construction and Permitting (\$6,500,000); and
 - 27 o Three additional projects totaling \$1,650,000, with no individual project
 - 28 exceeding \$750,000;

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- 2036: Four projects totaling \$4,650,000, which include:
 - o AQCS Equipment repair/replacement (\$3,000,000); and
 - o Three additional projects totaling \$1,650,000, with no individual project exceeding \$750,000;
- 2037: Four projects totaling \$2,400,000, with no individual project which exceeds \$750,000; and
- 2038: Two projects totaling \$550,600, with no individual project which exceeds \$300,000.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 2.

A. Exhibit A-51 (NJK-2) Revised, page 2, shows the Company's projected capital expenditures for Karn Units 3 and 4 for the cases in which Karn Units 3 and 4 retire on May 31, 2023 or May 31, 2025. As shown in Exhibit A-51 (NJK-2) Revised, page 2, column (c), there are no projected incremental capital expenditures for Karn Units 1 and 2 in these cases, which are discussed later in my direct testimony. The projected capital expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2) Revised, page 2, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 2, line 13, column (d), shows that the Company would avoid \$75,648,000 in capital expenditures if Karn Units 3 and 4 are retired on May 31, 2023. Exhibit A-51 (NJK-2) Revised, page 2, line 13, column (i), shows that the Company would avoid \$62,987,000 in capital expenditures if Karn Units 3 and 4 are retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 2, line 13, columns (e) and (j), shows that the Company would avoid \$15,465,000 in unit separation capital expenditures and \$9,161,000 in unit separation

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capital expenditures if Karn Units 3 and 4 are retired on May 31, 2023 and May 31, 2025 respectively.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 3.

A. Exhibit A-51 (NJK-2) Revised, page 3, shows the Company's projected capital expenditures for Campbell Unit 3 for the cases in which Campbell Unit 3 retires on May 31, 2025 or on May 31, 2032. The projected capital expenditures are shown for each calendar year from January 1, 2020 through May 31, 2039. Exhibit A-51 (NJK-2) Revised, page 3, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 3, line 21, columns (c) and (d), show that the Company would avoid \$190,613,000 in capital expenditures and \$64,146,000 in unit separation capital expenditures if Campbell Unit 3 is retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 3, line 21, columns (g) and (h), shows that the Company would avoid \$31,400,000 in capital expenditures and \$64,146,000 in unit separation capital expenditures if Campbell Unit 3 is retired on May 31, 2032. Campbell Units 1 and 2 are not reflected in Exhibit A-51 (NJK-2) Revised, page 3, because the Campbell Unit 3 early retirement case assumes that Campbell Units 1 and 2 retire in a similar timeframe and, therefore, have identical costs to those in the base case through 2026 and 2032.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 4.

A. Exhibit A-51 (NJK-2) Revised, page 4, shows the Company's projected capital expenditures for Campbell Units 1 and 2 for the cases in which Campbell Unit 1 retires on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2) Revised, page 4, also shows the difference in capital expenditures

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1 for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 4,
2 line 13, columns (d) and (e), shows that the Company would avoid \$42,840,000 in capital
3 expenditures if Campbell Unit 1 is retired on May 31, 2024 and Campbell Unit 2 would
4 incur incremental capital expenditures of \$253,000. Exhibit A-51 (NJK-2) Revised, page
5 4, line 13, columns (i) and (j), show that the Company would avoid \$35,951,000 in capital
6 expenditures at Campbell Unit 1 and incur no incremental capital expenditures at Campbell
7 Unit 2 if Campbell Unit 1 is retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page
8 4, line 26, columns (d) and (e), shows that the Company would avoid \$34,046,000 in capital
9 expenditures at Campbell Unit 1 and incur no incremental capital expenditures at Campbell
10 Unit 2 if Campbell Unit 1 is retired on May 31, 2026. Exhibit A-51 (NJK-2) Revised, page
11 4, line 26, columns (i) and (j), shows that the Company would avoid \$14,442,000 in capital
12 expenditures at Campbell Unit 1 and incur no incremental capital expenditures at Campbell
13 Unit 2 if Campbell Unit 1 is retired on May 31, 2028. Campbell Unit 3 is not reflected in
14 Exhibit A-51 (NJK-2) Revised, page 4, because the Campbell early retirement cases do not
15 have an impact on the Campbell Unit 3 capital expenditures as it is assumed that unit
16 separation capital expenditures reflected in the base case are not avoided.

17 **Q. Please explain Exhibit A-51 (NJK-2) Revised, page 5.**

18 A. Exhibit A-51 (NJK-2) Revised, page 5, shows the Company's projected capital
19 expenditures for Campbell Units 1 and 2 for the cases in which Campbell Unit 2 retires on
20 May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected
21 expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031.
22 Exhibit A-51 (NJK-2) Revised, page 5, also shows the difference in capital expenditures
23 for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 5,

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line 13, columns (d) and (e), shows that the Company would avoid \$56,070,000 in capital expenditures if Campbell Unit 2 is retired on May 31, 2024, and Campbell Unit 1 would incur incremental capital expenditures of \$322,000. Exhibit A-51 (NJK-2) Revised, page 5, line 13, columns (i) and (j), shows that the Company would avoid \$46,573,000 in capital expenditures at Campbell Unit 2 and incur no incremental capital expenditures at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 4, line 26, columns (d) and (e), shows that the Company would avoid \$45,273,000 in capital expenditures at Campbell Unit 2 and incur no incremental capital expenditures at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2026. Exhibit A-51 (NJK-2) Revised, page 4, line 26, columns (i) and (j), shows that the Company would avoid \$18,333,000 in capital expenditures at Campbell Unit 2 and incur no incremental capital expenditures at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-51 (NJK-2) Revised, page 5, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 capital expenditures as it is assumed that unit separation capital expenditures reflected in the base case are not avoided.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 6.

A. Exhibit A-51 (NJK-2) Revised, page 6, shows the Company's projected capital expenditures for Campbell Units 1 and 2 for the cases in which both Campbell Units 1 and 2 retire on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected capital expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2) Revised, page 6, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 6, line 13, columns (d) and (e), shows that the Company would avoid

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1 \$42,840,000 in capital expenditures at Campbell Unit 1 and \$56,070,000 in capital
2 expenditures at Campbell Unit 2 if both units are retired on May 31, 2024. Exhibit A-51
3 (NJK-2) Revised, page 6, line 13, columns (i) and (j), shows that the Company would avoid
4 \$35,951,000 in capital expenditures at Campbell Unit 1 and \$46,573,000 in capital
5 expenditures at Campbell Unit 2 if both units are retired on May 31, 2025. Exhibit A-51
6 (NJK-2) Revised, page 6, line 26, columns (d) and (e), shows that the Company would
7 avoid \$34,046,000 in capital expenditures at Campbell Unit 1 and \$45,273,000 in capital
8 expenditures at Campbell Unit 2 if both units are retired on May 31, 2026. Exhibit A-51
9 (NJK-2) Revised, page 6, line 26, columns (i) and (j), shows that the Company would avoid
10 \$14,442,000 in capital expenditures at Campbell Unit 1 and \$18,333,000 in capital
11 expenditures at Campbell Unit 2 if both units are retired on May 31, 2028. Campbell Unit
12 3 is not reflected in Exhibit A-51 (NJK-2) Revised, page 5, because the Campbell early
13 retirement cases do not have an impact on the Campbell Unit 3 capital expenditures
14 because the unit separation capital expenditures reflected in the base case are not avoided.

15 **Q. What is the basis for the projected major maintenance expenses in Exhibit A-52**
16 **(NJK-3), page 1, line 1?**

17 A. The major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 1, are those that
18 were used for 2020 in the Company's IRP modeling.

19 **Q. What is the basis for the projected major maintenance expenses in Exhibit A-52**
20 **(NJK-3), page 1, line 2?**

21 A. In 2021, the Company projects to spend:

- 22 • \$3,771,000 at Karn Units 1 and 2, covering 21 projects, none of which exceeds
23 \$700,000;

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- \$1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceeds \$250,000;
- \$11,930,200 at Campbell Units 1 and 2 including:
 - Campbell 2 Generator Overhaul-Rewedge-Collector Ring Replacement (\$3,630,000);
 - Campbell 2 Turbine Inspection and Overhaul (\$2,370,000);
 - Campbell 1 and 2 Periodic Outage Maintenance (\$1,512,000); and
 - Twenty-two additional projects totaling \$4,418,200, with no individual project exceeding \$750,000; and
- \$5,102,729 at Campbell Unit 3 including:
 - Campbell 3 Turbine Valve Inspection (\$1,200,000); and
 - Twenty-two additional projects totaling \$3,902,729, with no individual project exceeding \$715,000.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 3?

A. In 2022, the Company projects to spend:

- \$3,292,000 at Karn Units 1 and 2, covering 19 projects, none of which exceeds \$700,000;
- \$1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceed \$250,000;
- \$3,537,000 at Campbell Units 1 and 2 including:
 - Campbell 1 and 2 Periodic Outage Maintenance (\$1,248,000); and
 - Thirteen additional projects totaling \$2,289,000, with no individual project exceeding \$600,000; and
- \$4,208,040 at Campbell Unit 3 including:
 - Boiler Feed Pump Turbine Inspection (\$1,680,000); and
 - Fourteen additional projects totaling \$2,528,040, with no individual project exceeding \$425,000.

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1 **Q. What is the basis for the projected major maintenance expenses in Exhibit A-52**
2 **(NJK-3), page 1, line 4?**

3 A. In 2023, the Company projects to spend:

- 4 • \$826,000 at Karn Units 1 and 2, covering seven projects, none of which exceeds
5 \$200,000;
- 6 • \$1,000,000 at Karn Units 3 and 4, covering seven projects, none of which
7 exceeds \$250,000;
- 8 • \$2,905,000 at Campbell Units 1 and 2 covering 10 projects, none of which
9 exceeds \$643,667; and
- 10 • \$2,523,970 at Campbell Unit 3 covering 12 projects, none of which exceeds
11 \$425,000.

12 **Q. What is the basis for the projected major maintenance expenses in Exhibit A-52**
13 **(NJK-3), page 1, line 5?**

14 A. In 2024, the Company projects to spend:

- 15 • \$1,000,000 at Karn Units 3 and 4, covering seven projects, none of which
16 exceeds \$250,000;
- 17 • \$3,405,167 at Campbell Units 1 and 2 covering 12 projects, none of which
18 exceeds \$655,167; and
- 19 • \$12,954,250 at Campbell Unit 3 including:
 - 20 ○ Campbell 3 Turbine Overhaul (\$7,931,350);
 - 21 ○ Campbell 3 Boiler Chemical Cleaning (\$1,429,000);
 - 22 ○ Campbell 3 Base Outage Boiler and Critical Maintenance (\$1,000,000);
 - 23 ○ Campbell 3 Periodic Outage Maintenance (\$933,100); and
 - 24 ○ Eight additional projects totaling \$1,660,800, with no individual project
25 exceeding \$430,000.

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1 **Q. What is the basis for the projected major maintenance expenses in Exhibit A-52**
2 **(NJK-3), page 1, line 6?**

3 A. In 2025, the Company projects to spend:

- 4 • \$1,000,000 at Karn Units 3 and 4, covering seven projects, none of which
5 exceeds \$250,000;
- 6 • \$4,569,000 at Campbell Units 1 and 2 including:
 - 7 o Campbell 2 Turbine Valve Inspection (\$1,300,000); and
 - 8 o Seven additional projects totaling \$3,269,000, with no individual project
9 exceeding \$666,667; and
- 10 • \$3,810,600 at Campbell Unit 3 including:
 - 11 o Campbell 3 Turbine Valve Inspection (\$1,200,000);
 - 12 o Campbell 3 Base Outage Boiler and Critical Maintenance (\$1,100,000); and
 - 13 o Six additional projects totaling \$1,410,600, with no individual project
14 exceeding \$450,000.

15 **Q. What is the basis for the projected major maintenance expenses in Exhibit A-52**
16 **(NJK-3), page 1, line 7?**

17 A. In 2026, the Company projects to spend:

- 18 • \$1,000,000 at Karn Units 3 and 4, covering seven projects, none of which
19 exceed \$250,000;
- 20 • \$3,541,000 at Campbell Units 1 and 2 covering nine projects, none of which
21 exceed 678,167; and
- 22 • \$1,660,600 at Campbell Unit 3 covering five projects, none of which exceed
23 500,000.

24 **Q. What is the basis for the projected expenses in Exhibit A-52 (NJK-3), page 1, lines 8**
25 **through 20?**

26 A. In each year from 2027 through 2039 in the base case, the Company projects to incur major
27 maintenance expenses at Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3,

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as shown in Exhibit A-52 (NJK-3), page 1. The number of individual major maintenance projects for Karn Units 3 and 4 is as follows:

- 2027: Seven projects totaling \$1,000,000, with no individual project which exceeds \$250,000;
- 2028: Seven projects totaling \$1,000,000, with no individual project which exceeds \$250,000;
- 2029: Seven projects totaling \$1,000,000, with no individual project which exceeds \$250,000;
- 2030: Seven projects totaling \$800,000, with no individual project which exceeds \$250,000; and
- 2031: Three projects totaling \$250,000, with no individual project which exceeds \$150,000.

The number of individual major maintenance projects for Campbell Unit 1 is as follows:

- 2027: Seven projects totaling \$2,129,667, with no individual project which exceeds \$689,667;
- 2028: Six Projects totaling \$2,351,167, with no individual project which exceeds \$750,000;
- 2029: Six Projects totaling \$1,952,667, with no individual project which exceeds \$712,667;
- 2030: Four Projects totaling \$1,300,000, with no individual project which exceeds \$500,000; and
- 2031: Two Projects totaling \$300,000, with no individual project which exceeds \$200,000.

The number of individual major maintenance projects for Campbell Unit 2 is as follows:

- 2027: Seven projects totaling \$1,423,333, with no individual project which exceeds \$500,000;
- 2028: Six Projects totaling \$1,533,833, with no individual project which exceeds \$500,000;

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- 2029: Six Projects totaling \$3,294,333, which includes:
 - o Campbell 2 Turbine Valve Inspection (\$1,400,000); and
 - o Five Projects totaling \$1,894,333 with no individual project which exceeds \$500,000;
- 2030: Four Projects totaling \$1,204,833, with no individual project which exceeds \$404,833; and
- 2031: Two Projects totaling \$300,000, with no individual project which exceeds \$200,000.

The number of individual major maintenance projects for Campbell Unit 3 is as follows:

- 2027: Nine projects totaling \$2,560,600, with no individual project which exceeds \$500,000;
- 2028: Six Projects totaling \$1,830,600, with no individual project which exceeds \$500,000;
- 2029: Eight Projects totaling \$3,860,600, which includes:
 - o Campbell 3 Turbine Valve Inspection (\$1,300,000);
 - o Campbell 3 Base Outage Boiler and Critical Maintenance (\$1,100,000); and
 - o Six Projects totaling \$1,460,600 with no individual project which exceeds \$500,000;
- 2030: Six Projects totaling \$1,910,600, with no individual project which exceeds \$500,000;
- 2031: Seven Projects totaling \$1,960,600, with no individual project which exceeds \$500,000;
- 2032: Seven Projects totaling \$15,330,600, which includes:
 - o Campbell 3 Turbine Overhaul (\$12,000,000);
 - o Campbell 3 Base Outage Boiler and Critical Maintenance (\$2,000,000); and
 - o Five Projects totaling \$1,330,600 with no individual project which exceeds \$500,000;
- 2033: Eight Projects totaling \$3,860,600, which includes:
 - o Campbell 3 Turbine Valve Inspection (\$1,300,000);

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- o Campbell 3 Base Outage Boiler and Critical Maintenance (\$1,100,000); and
- o Six Projects totaling \$1,460,600 with no individual project which exceeds \$500,000;
- 2034: Five Projects totaling \$1,710,600, with no individual project which exceeds \$500,000;
- 2035: Eight Projects totaling \$2,260,600, with no individual project which exceeds \$500,000;
- 2036: Six Projects totaling \$1,850,600, with no individual project which exceeds \$500,000;
- 2037: Eight Projects totaling \$3,960,600, which includes:
 - o Campbell 3 Turbine Valve Inspection (\$1,400,000);
 - o Campbell 3 Base Outage Boiler and Critical Maintenance (\$1,100,000); and
 - o Six Projects totaling \$1,460,600 with no individual project which exceeds \$500,000;
- 2038: Five Projects totaling \$1,360,600, with no individual project which exceeds \$500,000; and
- 2039: Three Projects totaling \$310,600, with no individual project which exceeds \$110,600.

Q. Please explain Exhibit A-52 (NJK-3), page 2.

A. Exhibit A-52 (NJK-3), page 2, shows the Company's projected major maintenance expenses for Karn Units 3 and 4 for the cases in which Karn Units 3 and 4 retire on May 31, 2023 or May 31, 2025. The projected major maintenance expenses are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-52 (NJK-3), page 2, also shows the difference in major maintenance expenses for each calendar year relative to the base case. Exhibit A-52 (NJK-3), page 2, line 13, column (c), shows that the Company would avoid \$10,050,000 in major maintenance expenses if Karn Units 3 and 4 are retired on May 31, 2023. Exhibit A-52 (NJK-3), page 2, line 13, column (f), shows

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Summary of Projected Generation Operations Capital Expenditures

January 1, 2020 through May 31, 2039

(\$000)

Case No.: U-21090
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Generation Operations - Capital - Base Retirement Case

	(a)	(b)	(c)	(d)	(e)	(f)
Base Case - Retire Karn 1&2 5/31/2023, Campbell 1&2 & Karn 3&4 5/31/2031, Campbell 3 5/31/2039						
Line No.	Year	Karn 1/2 Total	Karn 3/4 Total	Campbell 1 Total	Campbell 2 Total	Campbell 3 Total
1	2020	7,176	8,679	10,025	9,268	12,860
2	2021	2,859	4,172	3,493	13,512	19,576
3	2022	2,135	15,416	7,300	5,257	17,125
4	2023	1,124	10,072	7,215	9,472	20,478
5	2024		9,775	9,753	11,252	33,396
6	2025		10,134	2,550	7,800	14,512
7	2026		9,900	3,300	4,420	4,400
8	2027		8,950	4,050	6,845	5,900
9	2028		2,000	3,500	7,394	4,400
10	2029		2,000	3,879	2,500	11,750
11	2030		1,000	2,564	1,050	11,150
12	2031		500	250	250	2,400
13	2032					2,750
14	2033					11,750
15	2034					5,400
16	2035					10,150
17	2036					4,650
18	2037					2,400
19	2038					550
20	2039					
21	Total	\$ 13,294	\$ 82,598	\$ 57,878	\$ 79,020	\$ 195,597

Notes:

1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

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(\$000)

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Date: October 2021

Generation Operations - Capital - Karn 3&4 Early Retirement Case

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Retire Karn 3&4 5/31/2023										
Line No.	Year	Karn 3&4 Total	Karn 1&2 Variance to Base Case	Karn 3&4 Variance to Base Case	Karn 3 & 4 Separation Variance to Base Case					
1	2020	5,500	-	(3,179)	-					
2	2021	750	-	(3,422)	-					
3	2022	500	-	(14,916)	(13,675)					
4	2023	200	-	(9,872)	(1,790)					
5	2024	-	-	(9,775)	-					
6	2025	-	-	(10,134)	-					
7	2026	-	-	(9,900)	-					
8	2027	-	-	(8,950)	-					
9	2028	-	-	(2,000)	-					
10	2029	-	-	(2,000)	-					
11	2030	-	-	(1,000)	-					
12	2031	-	-	(500)	-					
13	Total	\$ 6,950	\$ -	\$ (75,648)	\$ (15,465)					

Retire Karn 3 & 4 5/31/2025				
	Karn 3&4	Karn 1&2	Karn 3&4	Karn 3 & 4 Separation
Year	Total	ariance to Base Case	Variance to Base Case	Variance to Base Case
2020	8,679	-	-	-
2021	6,012	-	1,840	(667)
2022	2,370	-	(13,046)	(7,204)
2023	1,850	-	(8,222)	(1,290)
2024	500	-	(9,275)	-
2025	200	-	(9,934)	-
2026	-	-	(9,900)	-
2027	-	-	(8,950)	-
2028	-	-	(2,000)	-
2029	-	-	(2,000)	-
2030	-	-	(1,000)	-
2031	-	-	(500)	-
Total	\$ 19,611	\$ -	\$ (62,987)	\$ (9,161)

Note:

1. Cost of removal has not been included.

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Consumers Energy Company

Summary of Projected Generation Operations Capital Expenditures

January 1, 2020 through May 31, 2039

(\$000)

Case No.: U-21090
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Witness: NJKapala
Date: October 2021

Generation Operations - Capital - Campbell 3 Early Retirement Cases

	(a)	(b)	(c)	(d)	
	Retire Campbell 3 5/31/2025				
Line No.	Year	Campbell 3 Total	Campbell 3 ariance to Base Case	Campbell Unit 3 Separation Variance to Base Case	
1	2020	12,860	0	-	
2	2021	18,397	(1,179)	-	
3	2022	12,885	(4,240)	-	
4	2023	8,705	(11,773)	-	
5	2024	6,044	(27,352)	-	
6	2025	400	(14,112)	-	
7	2026	-	(4,400)	-	
8	2027	-	(5,900)	-	
9	2028	-	(4,400)	(6,780)	
10	2029	-	(11,750)	(14,341)	
11	2030	-	(11,150)	(28,683)	
12	2031	-	(2,400)	(14,341)	
13	2032	-	(2,750)	-	
14	2033	-	(11,750)	-	
15	2034	-	(5,400)	-	
16	2035	-	(10,150)	-	
17	2036	-	(4,650)	-	
18	2037	-	(2,400)	-	
19	2038	-	(550)	-	
20	2039	-	-	-	
21	Total	\$ 59,291	\$ (136,306)	\$ (64,146)	

	(e)	(f)	(g)	(h)	
	Retire Campbell 3 5/31/2032				
Year	Campbell 3 Total	Campbell 3 ariance to Base Case	Campbell Unit 3 Separation Variance to Base Case		
2020	12,860	0	-		
2021	19,576	-	-		
2022	17,125	-	-		
2023	20,478	-	-		
2024	33,396	-	-		
2025	14,512	-	-		
2026	4,400	-	-		
2027	5,900	-	-		
2028	4,400	-	(6,780)		
2029	8,750	(3,000)	(14,341)		
2030	11,150	-	(28,683)		
2031	2,400	-	(14,341)		
2032	2,750	-	-		
2033	-	(11,750)	-		
2034	-	(5,400)	-		
2035	-	(10,150)	-		
2036	-	(4,650)	-		
2037	-	(2,400)	-		
2038	-	(550)	-		
2039	-	-	-		
Total	\$ 157,697	\$ (37,900)	\$ (64,146)		

Notes:

1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

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Consumers Energy Company

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(\$000)

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Date: October 2021

Generation Operations - Capital - Campbell 1 Early Retirement Cases

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Retire Campbell 1 5/31/2024										
Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
1	2020	9,644	9,268	(381)	-	2020	9,989	9,268	(36)	-
2	2021	3,293	13,541	(200)	29	2021	3,293	13,512	(200)	-
3	2022	1,050	5,257	(6,250)	-	2022	3,810	5,257	(3,490)	-
4	2023	800	9,696	(6,415)	224	2023	3,784	9,472	(3,431)	-
5	2024	250	11,252	(9,503)	-	2024	800	11,252	(8,953)	-
6	2025	-	7,800	(2,550)	-	2025	250	7,800	(2,300)	-
7	2026	-	4,420	(3,300)	-	2026	-	4,420	(3,300)	-
8	2027	-	6,845	(4,050)	-	2027	-	6,845	(4,050)	-
9	2028	-	7,394	(3,500)	-	2028	-	7,394	(3,500)	-
10	2029	-	2,500	(3,879)	-	2029	-	2,500	(3,879)	-
11	2030	-	1,050	(2,564)	-	2030	-	1,050	(2,564)	-
12	2031	-	250	(250)	-	2031	-	250	(250)	-
13	Total	\$ 15,037	\$ 79,273	\$ (42,840)	\$ 253	Total	\$ 21,926	\$ 79,020	\$ (35,951)	\$ -

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Retire Campbell 1 5/31/2026										
Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
14	2020	9,989	9,268	(36)	-	2020	10,025	9,268	-	-
15	2021	3,293	13,512	(200)	-	2021	3,493	13,512	-	-
16	2022	3,810	5,257	(3,490)	-	2022	7,300	5,257	-	-
17	2023	4,073	9,472	(3,141)	-	2023	7,215	9,472	-	-
18	2024	1,616	11,252	(8,137)	-	2024	9,753	11,252	-	-
19	2025	800	7,800	(1,750)	-	2025	2,550	7,800	-	-
20	2026	250	4,420	(3,050)	-	2026	2,050	4,420	(1,250)	-
21	2027	-	6,845	(4,050)	-	2027	800	6,845	(3,250)	-
22	2028	-	7,394	(3,500)	-	2028	250	7,394	(3,250)	-
23	2029	-	2,500	(3,879)	-	2029	-	2,500	(3,879)	-
24	2030	-	1,050	(2,564)	-	2030	-	1,050	(2,564)	-
25	2031	-	250	(250)	-	2031	-	250	(250)	-
26	Total	\$ 23,831	\$ 79,020	\$ (34,046)	\$ -	Total	\$ 43,436	\$ 79,020	\$ (14,442)	\$ -

Notes:

1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

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Consumers Energy Company

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(\$000)

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Generation Operations - Capital - Campbell 2 Early Retirement Cases

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Retire Campbell 2 5/31/2024										
Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
1	2020	10,025	8,861	-	(407)	2020	10,025	9,219	-	(49)
2	2021	3,530	11,739	37	(1,773)	2021	3,493	13,271	-	(241)
3	2022	7,300	1,300	-	(3,957)	2022	7,300	5,107	-	(150)
4	2023	7,500	800	285	(8,672)	2023	7,215	3,800	-	(5,672)
5	2024	9,753	250	-	(11,002)	2024	9,753	800	-	(10,452)
6	2025	2,550	-	-	(7,800)	2025	2,550	250	-	(7,550)
7	2026	3,300	-	-	(4,420)	2026	3,300	-	-	(4,420)
8	2027	4,050	-	-	(6,845)	2027	4,050	-	-	(6,845)
9	2028	3,500	-	-	(7,394)	2028	3,500	-	-	(7,394)
10	2029	3,879	-	-	(2,500)	2029	3,879	-	-	(2,500)
11	2030	2,564	-	-	(1,050)	2030	2,564	-	-	(1,050)
12	2031	250	-	-	(250)	2031	250	-	-	(250)
13	Total	\$ 58,200	\$ 22,950	\$ 322	\$ (56,070)	Total	\$ 57,878	\$ 32,446	\$ -	\$ (46,573)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Retire Campbell 2 5/31/2026										
Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
14	2020	10,025	9,219	-	(49)	2020	10,025	9,268	-	-
15	2021	3,493	13,271	-	(241)	2021	3,493	13,512	-	-
16	2022	7,300	5,107	-	(150)	2022	7,300	5,257	-	-
17	2023	7,215	3,800	-	(5,672)	2023	7,215	9,472	-	-
18	2024	9,753	1,300	-	(9,952)	2024	9,753	11,252	-	-
19	2025	2,550	800	-	(7,000)	2025	2,550	4,800	-	(3,000)
20	2026	3,300	250	-	(4,170)	2026	3,300	3,170	-	(1,250)
21	2027	4,050	-	-	(6,845)	2027	4,050	3,706	-	(3,139)
22	2028	3,500	-	-	(7,394)	2028	3,500	250	-	(7,144)
23	2029	3,879	-	-	(2,500)	2029	3,879	-	-	(2,500)
24	2030	2,564	-	-	(1,050)	2030	2,564	-	-	(1,050)
25	2031	250	-	-	(250)	2031	250	-	-	(250)
26	Total	\$ 57,878	\$ 33,746	\$ -	\$ (45,273)	Total	\$ 57,878	\$ 60,687	\$ -	\$ (18,333)

(f)	(g)	(h)	(i)	(j)
Retire Campbell 2 5/31/2025				
	Campbell 1	Campbell 2	Campbell 1	Campbell 2
Year	Total	Total	Variance to Base Case	Variance to Base Case
2020	10,025	9,219	-	(49)
2021	3,493	13,271	-	(241)
2022	7,300	5,107	-	(150)
2023	7,215	3,800	-	(5,672)
2024	9,753	800	-	(10,452)
2025	2,550	250	-	(7,550)
2026	3,300	-	-	(4,420)
2027	4,050	-	-	(6,845)
2028	3,500	-	-	(7,394)
2029	3,879	-	-	(2,500)
2030	2,564	-	-	(1,050)
2031	250	-	-	(250)
Total	\$ 57,878	\$ 32,446	\$ -	\$ (46,573)

(f)	(g)	(h)	(i)	(j)
Retire Campbell 2 5/31/2028				
Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
2020	10,025	9,268	-	-
2021	3,493	13,512	-	-
2022	7,300	5,257	-	-
2023	7,215	9,472	-	-
2024	9,753	11,252	-	-
2025	2,550	4,800	-	(3,000)
2026	3,300	3,170	-	(1,250)
2027	4,050	3,706	-	(3,139)
2028	3,500	250	-	(7,144)
2029	3,879	-	-	(2,500)
2030	2,564	-	-	(1,050)
2031	250	-	-	(250)
Total	\$ 57,878	\$ 60,687	\$ -	\$ (18,333)

Notes:

1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

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(\$000)

Case No.: U-21090
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Generation Operations - Capital - Campbell 1 & 2 Early Retirement Cases

	(a)	(b)	(c)	(d)	(e)
	Retire Campbell 1&2 5/31/2024				
Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
1	2020	9,644	8,861	(381)	(407)
2	2021	3,293	11,739	(200)	(1,773)
3	2022	1,050	1,300	(6,250)	(3,957)
4	2023	800	800	(6,415)	(8,672)
5	2024	250	250	(9,503)	(11,002)
6	2025	-	-	(2,550)	(7,800)
7	2026	-	-	(3,300)	(4,420)
8	2027	-	-	(4,050)	(6,845)
9	2028	-	-	(3,500)	(7,394)
10	2029	-	-	(3,879)	(2,500)
11	2030	-	-	(2,564)	(1,050)
12	2031	-	-	(250)	(250)
13	Total	\$ 15,037	\$ 22,950	\$ (42,840)	\$ (56,070)

	(a)	(b)	(c)	(d)	(e)
	Retire Campbell 1&2 5/31/2026				
Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
14	2020	9,989	9,219	(36)	(49)
15	2021	3,293	13,271	(200)	(241)
16	2022	3,810	5,107	(3,490)	(150)
17	2023	4,073	3,800	(3,141)	(5,672)
18	2024	1,616	1,300	(8,137)	(9,952)
19	2025	800	800	(1,750)	(7,000)
20	2026	250	250	(3,050)	(4,170)
21	2027	-	-	(4,050)	(6,845)
22	2028	-	-	(3,500)	(7,394)
23	2029	-	-	(3,879)	(2,500)
24	2030	-	-	(2,564)	(1,050)
25	2031	-	-	(250)	(250)
26	Total	\$ 23,831	\$ 33,746	\$ (34,046)	\$ (45,273)

	(f)	(g)	(h)	(i)	(j)
	Retire Campbell 1&2 5/31/2025				
Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	
2020	9,989	9,219	(36)	(49)	
2021	3,293	13,271	(200)	(241)	
2022	3,810	5,107	(3,490)	(150)	
2023	3,784	3,800	(3,431)	(5,672)	
2024	800	800	(8,953)	(10,452)	
2025	250	250	(2,300)	(7,550)	
2026	-	-	(3,300)	(4,420)	
2027	-	-	(4,050)	(6,845)	
2028	-	-	(3,500)	(7,394)	
2029	-	-	(3,879)	(2,500)	
2030	-	-	(2,564)	(1,050)	
2031	-	-	(250)	(250)	
Total	\$ 21,926	\$ 32,446	\$ (35,951)	\$ (46,573)	

	(f)	(g)	(h)	(i)	(j)
	Retire Campbell 1&2 5/31/2028				
Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	
2020	10,025	9,268	-	-	
2021	3,493	13,512	-	-	
2022	7,300	5,257	-	-	
2023	7,215	9,472	-	-	
2024	9,753	11,252	-	-	
2025	2,550	4,800	-	(3,000)	
2026	2,050	3,170	(1,250)	(1,250)	
2027	800	3,706	(3,250)	(3,139)	
2028	250	250	(3,250)	(7,144)	
2029	-	-	(3,879)	(2,500)	
2030	-	-	(2,564)	(1,050)	
2031	-	-	(250)	(250)	
Total	\$ 43,436	\$ 60,687	\$ (14,442)	\$ (18,333)	

Notes:

1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Midcontinent)
Independent System Operator)
(MISO))

Order No. 202-26-16

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 14

Hoffman 2024 Direct
Testimony

1 STATE OF MICHIGAN
2 BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION
3 In the matter of the application
4 of CONSUMERS ENERGY COMPANY for Case No. U-21258
5 reconciliation of its power supply Volume 2
6 recovery plan (Case No. U-21257)
7 for the twelve months ended
8 December 31st, 2023. * PUBLIC *

6 _____/

7 REVISED
8 CROSS-EXAMINATION

9 Proceedings held via Microsoft Teams
10 in the above-entitled matter before Sally L. Wallace,
11 Administrative Law Judge with MOAHR, for the Michigan
12 Public Service Commission, Lansing, Michigan, on
13 Thursday, March 20, 2025, at 9:07 AM.

14 APPEARANCES:

15 EVAN B. KEIMACH, ESQ.
16 Consumers Energy Company
17 One Energy Plaza
18 Jackson, Michigan 49201

17 On behalf of Consumers Energy Company

18 THOMAS J. WATERS, ESQ.
19 The Running Wise Law Firm
20 1501 Cass Street, Suite D
21 Traverse City, Michigan 49684-4157
22 On Behalf of Biomass Merchant Plants
23
24

25 (Continued)

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for reconciliation of its power supply cost	)	Case No. U-21258
recovery plan (Case No. U-21257)	)	
for the 12 months ended December 31, 2023.	)	
_____	)	

REVISED DIRECT TESTIMONY

OF

NATHAN J. HOFFMAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

March 2024

NATHAN J. HOFFMAN
U-21258 REVISED DIRECT TESTIMONY

1 **Q. Please state your name and business address.**

2 A. My name is Nathan J. Hoffman, and my business address is One Energy Plaza, Jackson,
3 Michigan 49201.

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

5 A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”)
6 as Executive Director – Fossil Generation.

7 **Q. Please describe your educational background.**

8 A. In 2003, I received a Bachelor of Science degree in Welding Engineering Technology from
9 Ferris State University. In 2017, I received a Master of Business Administration with a
10 concentration in Advanced Management Tools and Concepts from Ferris State University.

11 **Q. Please describe your business experience.**

12 A. In 2005, I joined Consumers Energy at the J.H. Campbell (“Campbell”) Generating
13 Complex and progressed through positions from Engineering Technical Analyst to the
14 Executive Director – Fossil Generation. In my various roles at Consumers Energy, I served
15 as a subject matter expert for boiler and piping systems and was an embedded engineering
16 resource in the Operations Department responsible for monitoring plant performance and
17 troubleshooting. I also planned and executed outages to ensure that they were performed
18 in a prudent and expeditious manner, as well as managed the site maintenance organization
19 tasked with maintaining the plant systems and equipment. As the Executive Director –
20 Fossil Generation, I have overall responsibility for the safe and excellent operations of the
21 Fossil Generation Fleet. In this role, I also manage the overall Operating and Maintenance
22 and Capital budgets, develop site specific staffing plans, develop strategies to meet
23 Company objectives, and instill a culture of continuous improvement. I further oversee

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the performance of the Site's Operations, Maintenance, Fuel Handling, and Environmental and Technical Services departments.

Q. Have you previously provided testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I provided testimony in the Company's 2023 Power Supply Cost Recovery ("PSCR") Plan, Case No. U-21257; the Company's 2024 PSCR Plan, Case No. U-21423; and the Company's 2022 PSCR Reconciliation, Case No. U-21049.

Purpose of Direct Testimony

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

A. The purpose of my direct testimony is to:

- Describe the reasonableness and prudence of certain outages experienced in 2023 at the Company's fossil-fueled electric generating units and the River Hydroelectric generating units ("River Hydros");
- Describe the outages experienced in 2023 at the Company's Ludington Pumped Storage Plant ("Ludington"), including the outages at Ludington resulting from faulty work performed by Toshiba America Energy Systems Corporation ("TAES"), and the associated costs, which the Company has recorded to the regulatory asset approved by the Commission in Case No. U-21310;
- Explain the expense associated with emission allowances for oxides of nitrogen ("NO_x") and Sulfur Dioxide ("SO₂");
- Explain the expense associated with the consumption of urea, aqueous ammonia, lime, and activated carbon;
- Explain the 2023 performance of the Company's owned wind assets; and
- Explain the treatment of the replacement power costs associated with Ludington unit outages resulting from the defective work performed by TAES.

Q. Are you sponsoring exhibits with your direct testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-10 (NJH-1)	Event Summary Report, January 2023 to December 2023;

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1	Exhibit A-11 (NJH-2)	Event Identification – Outages;
2	Exhibit A-12 (NJH-3)	Periodic Outage Reports;
3	Exhibit A-13 (NJH-4)	2023 Fossil and Pumped Storage Outages Occurring
4		for Twenty-Eight Days or More;
5	Exhibit A-14 (NJH-5)	Generation Performance Statistics (January 1, 2023
6		to December 31, 2023);
7	Exhibit A-15 (NJH-6)	Comparison of Consumers Energy and GADS
8		Averages for Similar Units Equivalent Availability;
9	Exhibit A-16 (NJH-7)	2023 Base Load Generation Power Plant Cost
10		Efficiency;
11	Exhibit A-17 (NJH-8)	Chemical Reagent Expense (January 1, 2023 to
12		December 31, 2023);
13	Exhibit A-18 (NJH-9)	2023 Wind Asset Performance Data; and
14	Exhibit A-19 (NJH-10) Revised	2023 Ludington Outages.

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

16 A. Yes.

17 **2023 Outages**

18 **Q. Have you provided a listing of all 2023 outages?**

19 A. Yes. The Event Summary Report, Exhibit A-10 (NJH-1), lists all unit outages and trips.

20 The report shows 35 events on the coal units, 124 on the Ludington Units, 64 on the

21 Zeeland Combined Cycle Plant (“Zeeland CC”) (Units 3, 4, and 5), Covert Gas Plant

22 (“Covert”), and Jackson Gas Plant (“Jackson”), 37 on D.E. Karn (“Karn”) Units 3 and 4,

23 22 on the Zeeland Simple Cycle (“Zeeland SC”) (Units 1 and 2), and 142 on the River

24 Hydro units. The total number of outage events for the fleet was 424 in 2023, 99 fewer

25 than in 2022.

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Exhibit A-10 (NJH-1) provides a description of each event, including the event start time, event end time, cause code,¹ duration in equivalent hours, and equivalent MWh. The equivalent MWh calculation assumes that the units would have operated at 100% capacity factor.

Q. Has the Company also calculated the lost generation for the Ludington Units in accordance with the Settlement Agreement approved in the Commission's June 28, 2018 Order in Case No. U-17918-R?

A. Yes. Company witness Joshua W. Hahn provides the economic MWh loss calculations for the Ludington Units assuming they were operating and dispatchable. These calculations are presented in Exhibit A-9 (JWH-3).

Q. Would you please define the words "outage," "trip," and "event"?

A. A unit "outage" on a base-load unit is defined as the period from when the circuit breaker opens, separating the unit from the electric system, to when it closes, tying the unit to the electric system and making it available for dispatch, and the unit is not in economic reserve status. A unit "outage" on a cycling or peaking unit is defined as the period from when the Company's Electric Supply Operations Department releases a unit, making it unavailable, to when the plant reports to Electric Supply Operations that the unit is available for service. For the purposes of these definitions, the coal and river hydro units are considered base-load units, and the Zeeland, Jackson, Covert, and Karn Units 3 and 4 are all considered cycling units. Zeeland Units 1 and 2 are considered peakers. Base load generation refers to the minimum amount of electric power required to be delivered to customers over a

¹ Cause codes used are taken from the Data Reporting Instructions of the North American Electric Reliability Corporation ("NERC") Generating Availability Data System. Explanations for the cause codes can be found at: [Data Reporting Instructions \(nerc.com\)](https://www.nerc.com/Data-Reporting-Instructions)

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1 given period of time at a steady rate. Base load generating units are units which are
2 typically operated to serve customer loads on an around-the-clock basis.

3 A “trip” is a unit outage that begins when protective devices automatically separate
4 a unit from the electric system, or the operator initiates a manual and immediate separation.
5 This is in contrast to the normal controlled shutdown process where operators may spend
6 several hours slowly reducing pressure and load before separating the unit from the system.

7 An “event” is a one-line entry on the Event Summary Report. Each line on the
8 Report contains an outage “event.” The outage event classification is divided into eight
9 distinct event types: (i) Planned Outage; (ii) Maintenance Outage; (iii) Planned Outage
10 Extension; (iv) Maintenance Outage Extension; (v) Startup Failure; (vi) Unplanned
11 (Forced) Outage-Immediate; (vii) Unplanned (Forced) Outage-Delayed; and
12 (viii) Unplanned (Forced) Outage-Postponed. Exhibit A-11 (NJH-2) explains the different
13 types of outages shown on Exhibit A-10 (NJH-1).

14 **Q. Have you documented outage occurrences in more detail?**

15 A. Yes. In addition to documenting all of the 2023 outages reported on page 3 of this
16 testimony and reflected in Exhibit A-10 (NJH-1), outage information sheets were also
17 prepared for generating units that had lower availability averages than those shown in
18 Generating Availability Data System (“GADS”) data discussed later in my direct
19 testimony. The information sheets are provided as Exhibit A-12 (NJH-3). Each sheet
20 contains the same statistical data found on Exhibit A-10 (NJH-1), as well as: (i) an
21 expanded description of the event; (ii) a cause of the event; (iii) the work that was done to
22 correct the root cause for forced outages or the work that was performed during
23 maintenance and periodic outages; (iv) other work, if any, that was performed; (v) a

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1 description of work that extended the outage, if any extension occurred; and (vi) why that
2 work was performed.

3 Additionally, the Company prepared a Periodic Outage, Maintenance Outage, or
4 Forced Outage Information sheet for each of the events lasting 28 days or more on the
5 fossil, pumped storage, peaking, and River Hydro units shown on Exhibit A-10 (NJH-1).

6 **Q. Before discussing specific outages, do you have any general comments about outages**
7 **in the Company's generation fleet?**

8 A. Yes, particularly concerning the Company's older units. Some of these units were built in
9 the 1960s, and given the ages and designs of the systems, replacement parts are not always
10 readily available. In some instances, replacement parts do not exist at all. The start-up
11 boiler feed pump ("SUBFP") at Campbell Unit 2 is one of those systems. Keeping spare
12 parts on hand is neither cost effective nor practical since replacements do not exist, and
13 while I outline the incredible efforts taken to repair the SUBFP, it remains offline.

14 **Fossil, Cycling, and Pumped Storage Outages Planned for 28 Days or More**

15 **Q. In Case No. U-21257, how many outages were planned for 28 days or more?**

16 A. My direct testimony and Exhibit A-11 (NJH-1) identified twelve such outages.

17 **Q. Were all twelve outages completed during the plan year?**

18 A. No. Only eight of the planned outages were completed during the plan year; the planned
19 outages for Campbell Unit 1, Karn Unit 2, Karn Unit 3, and Karn Unit 4 were not
20 performed.

21 **Q. Why wasn't the planned outage at Campbell Unit 1 performed?**

22 A. The Campbell Unit 1 outage was scheduled to begin on October 13, 2023 and last for
23 31 days. However, the unit had been placed into economic reserve status on February 19,
24 2023 and subsequently began a maintenance outage on March 7, 2023. The maintenance

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1 outage lasted for 14 days, ending on March 21, 2023. During this timeframe, all priority
2 work scope that was scheduled for the fall outage was completed, obviating the need for
3 the planned outage scheduled to begin on October 13, 2023.

4 **Q. Why wasn't the planned outage at Karn Unit 2 performed?**

5 A. The outage at Karn Unit 2 was scheduled to begin May 1, 2023 and was projected to last
6 for 30 days – concluding May 31, 2023. The outage was scheduled to perform preparation
7 activities for unit cessation on May 31, 2023. However, due to the need to burn down the
8 remaining coal, the outage was not taken as planned. A maintenance outage was taken for
9 11 days in early May to perform visual inspections of backpass, pulse jet fabric filters, and
10 the selective catalytic reduction vessels to quantify the ash accumulation needing to be
11 abated upon cessation of operations.

12 **Q. Why weren't the planned outages for Karn Units 3 and 4 performed?**

13 A. The Karn Unit 3 and 4 outages were not performed due to availability of materials for the
14 major work that was planned. Due to the uncertainty of the retirement of Karn Units 3
15 and 4 as proposed in the Company's 2021 Integrated Resource Plan ("IRP"), the
16 preparation for these outages was not complete, including material delivery. As such the
17 planned work was deferred to 2024.

18 **Q. Did the Company conduct additional outages of 28 days or more in 2023?**

19 A. Yes. In addition to the eight planned outages which lasted longer than 28 days, the
20 Company conducted two additional outages for a total of ten outages that lasted 28 days or
21 more. The additional outages included Campbell Unit 2 and Karn Unit 3. All ten outages
22 are identified in Exhibit A-13 (NJH-4).

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1 **Q. Has your review of the outages listed in Exhibit A-13 (NJH-4) led you to a conclusion**
2 **concerning these outages?**

3 A. Yes. I have concluded that all of the outages listed in Exhibit A-13 (NJH-4) were carefully
4 planned, prudently managed, and free of negligence on the part of Consumers Energy as
5 to either causation or extension of outage time. Below is a brief summary of each of the
6 outages listed in Exhibit A-13 (NJH-4).

7 **Campbell Unit 2**

8 The Campbell Unit 2 outage began on August 4, 2023 due to a tube leak in the hydraulic
9 coupling circuit oil cooler. The tube leak resulted in water intrusion into the oil system,
10 thereby forcing the unit to be removed from service. Subsequently, on August 10, 2023,
11 the SUBFP experienced a thrust event causing damage to the internal flow element, thrust
12 bearing, and drive coupling. The unit was out of service for the remainder of the year, a
13 total of 149 days. A detailed discussion of the extended outage is provided later in this
14 direct testimony.

15 **Campbell Unit 3**

16 The outage at Campbell Unit 3 was scheduled to begin April 1, 2023 and was projected to
17 last for 42 days – concluding May 13, 2023. The outage began on March 31, 2023 and
18 lasted 40 days, ending on May 10, 2023. The outage was necessary for the planned
19 replacement of a catalyst layer in the Selective Catalytic Reduction (“SCR”) vessel and
20 repair of a suspected boiler waterwall leak. In addition, performance of NERC testing was
21 required following substation modifications necessary to support site decommissioning.

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Karn Unit 3

The outage at Karn Unit 3 was scheduled to begin March 5, 2023 and was projected to last for 41 days – concluding April 15, 2023. The outage began on March 5, 2023 and lasted for 41 days, ending on April 15, 2023. The outage was necessary for the performance of cooling tower repairs. In addition, the Company conducted NERC relay testing, replaced substation generator circuit breaker controls, performed miscellaneous balance of plant mechanical repairs, and removed three cooling fan assemblies for overhaul.

Karn Unit 3

The outage at Karn Unit 3 began on May 31, 2023 and lasted 102 days – concluding September 10, 2023. The outage was caused by the failure of one of the J-strap connectors which connects the exciter rotor to its windings. The work required to restore the unit to service included disassembly of the exciter for shipment to a vendor for inspection and rewind of the rotor windings. A detailed discussion of the extended outage is provided later in this direct testimony.

Ludington Unit 5

The outage at Ludington Unit 5 was scheduled to begin May 15, 2023 and was projected to last for 40 days – concluding June 24, 2023. The outage began on May 15, 2023 and lasted for 46 days, ending on June 30, 2023. The outage was necessary for the annual periodic outage warranty inspections, main transformer bank #3 inspections, turbine lube oil coolers maintenance, and wicket gate thrust collar and seal inspections and repairs. The outage was extended due to failure of the emergency intake gate hoist control. A failed silicon-controlled rectifier and power resistor for the DC control led to this failure and the replacement of those components rectified the issue.

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Ludington Unit 6

The outage at Ludington Unit 5 was scheduled to begin May 15, 2023 and was projected to last for 40 days – concluding June 24, 2023. The outage began on May 15, 2023 and lasted for 39 days, ending on June 23, 2023. The outage was necessary for the annual periodic outage warranty inspections, main transformer bank #3 inspections, turbine lube oil coolers maintenance, and wicket gate thrust collar and seal inspections and repairs.

Zeeland Unit 1

The Zeeland Unit 1 outage began on December 27, 2022 and lasted for a total of 100 days, 96 days in 2023, ending on April 7, 2023. The outage was necessary due to the need for the Company to move the leased generator step-up (“GSU”) transformer from Zeeland Unit 1 to Zeeland Unit 5. The basis for the decision to move the leased GSU transformer to Zeeland Unit 5 is the increased economics of Zeeland Unit 5 due to its operation as a combined cycle unit versus that of Zeeland Unit 1 which is a single cycle unit. A detailed discussion of the extended outage is provided later in this direct testimony.

Zeeland Unit 3

The outage at Zeeland Unit 3 was scheduled to begin September 22, 2023 and was projected to last for 57 days – concluding November 18, 2023. The outage began on November 4, 2023 and lasted for 40 days, ending on December 14, 2023. The outage was necessary for the planned inspection and repair of the unit pursuant to requirements of the Long-Term Service Agreement (“LTSA”) based upon unit operating hours.

Zeeland Unit 4

The outage at Zeeland Unit 4 was scheduled to begin September 22, 2023 and was projected to last for 57 days – concluding November 18, 2023. The outage began on

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1 November 4, 2023 and lasted for 39 days, ending on December 13, 2023. The outage was
2 necessary for the planned inspection and repair of the unit pursuant to requirements of the
3 LTSA based upon unit operating hours.

4 **Zeeland Unit 5**

5 The outage at Zeeland Unit 5 was scheduled to begin September 22, 2023 and was
6 projected to last for 57 days – concluding November 18, 2023. The outage began on
7 November 4, 2023 and lasted for 39 days, ending on December 13, 2023. The outage was
8 necessary for the planned inspection and repair of the unit pursuant to requirements of the
9 LTSA based upon unit operating hours.

10 **Q. Did the Company conduct any outages that exceeded 90 days in duration?**

11 A. Yes. The Company conducted three outages during 2023 that exceeded 90 days in
12 duration. The first of these was the Zeeland Unit 1 outage which began in December 2022
13 and lasted for 96 days during 2023. The additional outages that exceeded 90 days in
14 duration were the Campbell Unit 2 outage which lasted for 149 days during 2023 and the
15 Karn Unit 3 outage which lasted for 102 days during 2023.

16 **Q. Why did the Zeeland Unit 1 outage exceed 90 days?**

17 A. As previously discussed in this direct testimony, the Zeeland Unit 1 outage began on
18 December 27, 2022, upon the economic changeout of the spare GSU (leased) transformer
19 from Zeeland Unit 1 to Zeeland Unit 5. The leased GSU transformer was installed on
20 Zeeland Unit 1 in May 2022, subsequent to the failure of the originally-installed GSU
21 transformer on Zeeland Unit 1. The outage lasted for a total of 100 days, 96 days in 2023,
22 and the unit was returned to service on April 7, 2023, upon return of the repaired GSU
23 transformer.

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1 **Q. Why was the original GSU transformer for Zeeland Unit 1 removed?**

2 A. The original equipment manufacturer recommended that the original transformer not be
3 re-energized due to elevated and rising acetylene gas concentrations measured in the
4 transformer. High concentrations of acetylene in a transformer are an indication of defects
5 that may induce transformer failure. As a result, the original transformer was removed
6 from service after efforts to identify the cause of elevated acetylene indicated evidence of
7 possible low voltage winding damage.

8 **Q. Does the Company routinely monitor the condition of its GSU transformers?**

9 A. Yes. Specifically, at Zeeland, the Company monitors all GSU transformers with
10 continuous gas analyzers. In addition, oil testing is performed on an annual basis and
11 routine transformer maintenance is regularly performed to help prevent unplanned failures.
12 The Company reasonably and prudently monitored and maintained its transformer and did
13 not cause the transformer to fail nor cause the outage extension. The Company's
14 monitoring efforts allowed it to identify imminent failure of the GSU transformer for
15 Zeeland Unit 5 and take actions to swap the leased GSU transformer installed on Zeeland
16 Unit 1 and install it on Zeeland Unit 5 in order to minimize customer power costs.

17 **Q. Please discuss the condition of Zeeland Unit 5?**

18 A. On August 24, 2022, an alarm for the Unit 5 GSU Transformer on rising levels of Methane
19 was noted by a plant operator. An investigation of the dissolved gas analysis trends
20 revealed that there was an exponential increase in dissolved gases starting around
21 August 10, 2022. The rate of rise continued to increase until the unit went into a planned
22 outage on September 17, 2022. During that period Hydrogen increased from 36 to
23 135 ppm, Methane 81 to 218 ppm, Ethane 43 to 90 ppm, and Ethylene 36 to 157 ppm. The

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gassing ratios indicated a thermal fault 300 to 700 C and possible carbonization of paper, per IEEE C57.104-2019 interpretation. Due to the alarming rate of rise, the Company performed an unplanned internal inspection of the transformer during the fall 2022 Phase 2 outage. The internal inspection and testing revealed:

- The Low Voltage (“LV”) bushings had effectively failed in service;
- The transformer core ground connection was missing since commissioning in 2001;
- The LV connections internal to the transformer had indications of severe heating; and
- The IsoPhase bus shielding duct was in contact with the LV bushing housings on all three phases potentially creating a local circulating current and heat.

As result of the findings, the following corrective actions were taken:

- The transformer was drained;
- The LV bushings were replaced with surplus bushings. The “new” bushings were not a “like-for like” replacement and several modifications were made to the bus bar connections to adapt them to the existing configuration;
- The core ground was terminated;
- IsoPhase bus was isolated from the LV bushing housings with an air gap; and
- The transformer was then filled with oil.
- Electrical tests on the transformer were repeated to ensure equipment functionality. The tests indicated that the LV winding insulation had moderately aged, but was acceptable to put the transformer back in service.
- The transformer was returned to service on October 11, 2022.

Q. What were the results of the corrective actions?

A. The corrective actions had little effect on the rate of gassing after the transformer was returned to service. The unit was removed from service on December 17, 2022 and shipped

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1 to Hitachi (Stoney Creek) for overhaul and a temporary mobile GSU was installed in place,
2 to keep Phase 2 available for customers.

3 **Q. Why did the Karn Unit 3 outage exceed 90 days?**

4 A. As previously discussed in this direct testimony, the outage was unplanned and was a result
5 of failure of one of the j-strap connectors which led to a failure to provide proper excitation
6 to the generator. The j-strap connectors are used to provide flexibility as the exciter heats
7 up under load.

8 **Q. When was the exciter last inspected for condition?**

9 A. The exciter was last electrically tested during the 2022 outage with no indication of pending
10 failure. The j-straps are not able to be visually inspected without removal of the rotor's
11 end caps, an activity that can only be performed during a tear down in a vendor's shop.

12 **Q. What action did the Company take to resolve the exciter failure?**

13 A. As a result of the failure, the exciter was disassembled and shipped to a vendor facility for
14 inspection and repair of the rotor windings. The Company has reasonably and prudently
15 inspected the exciter during the previous outage and did not cause the exciter to fail. The
16 Company's actions did not extend the outage in any manner.

17 **Q. Why did the Campbell Unit 2 outage exceed 90 days?**

18 A. As previously discussed in this direct testimony, the Campbell Unit 2 outage began on
19 August 4, 2023 because of a tube leak in the hydraulic coupling circuit oil cooler which
20 resulted in water intrusion into the oil system, thereby forcing the unit to be removed from
21 service.

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1 **Q. What work was performed to address the tube leak and what was the root cause of**
2 **the failure?**

3 A. The tube leak was repaired by plugging the tube and water was removed from the oil system
4 by vacuum dehydrating the oil. The mode of failure for the tube leak was not determined
5 as the tube bundle was not pulled due to short plant life remaining and the fact that no spare
6 tube bundle was available. During post-maintenance testing on August 10, 2023, the
7 SUBFP experienced a thrust event which resulted in damage to the SUBFP internal flow
8 element, thrust bearing, and drive coupling.

9 **Q. What was the root cause of the SUBFP failure?**

10 A. During testing, the SUBFP was unable to generate sufficient pressure and mass flow rate
11 to allow for unit escalation. This resulted in damage to the internal flow element, thrust
12 bearing, and drive coupling. This damage was a result of operational contact between the
13 internal flow element and the pump housing that occurred during the thrust event. The
14 cause of the failure was the thrust event, and the cause of that event is still under
15 investigation.

16 **Q. What work was performed to restore the SUBFP?**

17 A. Following the thrust event, the SUBFP was disassembled and rebuilt. An exact
18 replacement for the drive coupling was not readily available, so the SUBFP was rebuilt
19 with a replacement drive coupling. An identical replacement coupling had a 33-week lead
20 time, and the Company made a decision to get the unit back on-line with a replacement
21 drive coupling. On September 29, 2023, subsequent to the SUBFP rebuild, post
22 maintenance testing was performed which resulted in unacceptably high vibration levels;

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1 the SUBFP experienced high radial vibrations during start up on both the inboard and
2 outboard bearings. As such, the SUBFP was deemed unsafe to operate.

3 **Q. What work was performed to resolve the high vibration levels for the SUBFP?**

4 A. The SUBFP was again disassembled and inspected. While still under investigation, the
5 root cause of the high vibration was assessed to be related to replacement of the drive
6 coupling which is approximately 67 pounds heavier than the original. Additional repair
7 efforts included performance of high-speed balance with no success, inspection of the
8 structural frame and housing of the SUBFP for damage that could cause a shift in the
9 natural operating frequency of the SUBFP with no findings, and installation of dynamic
10 vibration absorbers on both the inboard and outboard bearings to shift the structural natural
11 frequency away from the pump operating frequency. While this last effort resulted in an
12 improvement in radial vibration, the improvement did not bring the vibration within
13 acceptable levels, and vibration anomalies were transmitted to the pump motor placing that
14 component at risk of failure.

15 **Q. What additional work is the Company performing to resolve the high vibration levels**
16 **for the SUBFP?**

17 A. The Company has been performing detailed modeling of the pump/motor/gearbox
18 assembly in order to select and/or design new coupling options. Detailed analysis by
19 industry experts (HydroAire) point to the source of the vibrations related to the change in
20 rotational inertia caused by the change in coupling mass. Unfortunately, none of the
21 Company's efforts had yielded positive results through year-end 2023 and the unit was out
22 of service for the remainder of the year, a total of 149 days.

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The Company rigorously investigated, evaluated, and implemented alternatives to restore the SUBFP to service, and continues to do so. The unavailability of an identical drive coupling (lead time of 33 weeks) led the Company to pursue reasonable alternatives to restore Campbell Unit 2 to service. The Company did not cause the failure of the SUBFP, nor did its actions extend the outage, rather it managed the SUBFP restoration activities in a reasonable, prudent, and responsible manner throughout the 2023 outage duration.

Q. Have you reviewed the peaker and hydro unit outages?

A. Yes. I reviewed the events for each peaker and hydro unit shown on the Event Summary Report, Exhibit A-10 (NJH-1). As previously discussed, Zeeland Unit 1 was the only peaker outage that lasted longer than 28 days in 2023.

River hydro outages greater than 28 days are summarized in the table below:

Line No.	Hydro Unit	Actual Days in 2023	Event Number(s)
1	CROTON 1	271	1
2	CROTON 2	271	1
3	CROTON 4	35	6
4	FIVE CHANNELS 1	46	6
5	FIVE CHANNELS 2	112	3
6	HARDY 2	107	3, 5
7	HODENPYL 1	151	4
8	MIO 2	59	2
9	MIO 2	122	4, 5
10	ROGERS 3	210	1
11	ROGERS 4	210	1
12	WEBBER 1	53	1, 2
13	WEBBER 2	110	3, 4

My review of these events and the additional information provided on Exhibit A-12 (NJH-3) leads me to conclude that those outages were conducted in a prudent manner.

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Outages with a Duration of Fewer Than 28 Days

Q. How many periodic outages less than 28 days but greater than one day in length occurred on the fossil and Ludington Units in 2023?

A. As shown on Exhibit A-10 (NJH-1), 34 short periodic (planned) outages occurred on the fossil and Ludington Units in 2023.

Q. What was the purpose of these periodic outages?

A. In general, the purpose of these outages was to perform preventative maintenance activities on equipment that has been assessed as being non-functional or having gone more than one to two years without preventative or corrective maintenance.

Availability

Q. Please discuss the Company's 2023 generation unit availability.

A. The Company's 2023 generation unit availability data is shown on Exhibit A-14 (NJH-5). The Company's Total Fossil MWh availability slightly decreased from 74.76% in 2022 (see Case No. U-21049, Exhibit A-13 (NJH-5), line 11, column (c)) to 74.58% in 2023 (see Exhibit A-14 (NJH-5), line 12, column (c)), due to decreases in MWh availability at Campbell Units 2 and 3, Karn Unit 2, and the Zeeland combined cycle units. The lower MWh availability at the aforementioned units was offset by the increased MWh availability at Campbell Unit 1 and the addition of the Covert units to the generation resource mix. The MWh availability at Campbell Unit 2 was lower due to an extended outage as discussed earlier in this direct testimony, the MWh availability at Campbell Unit 3 was lower due to several forced outages due to boiler and superheat tube leaks, the MWh availability at Karn Unit 2 was lower due to a forced outage to repair boiler leaks and a maintenance outage to perform pre-retirement cessation activities, and the MWh

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1 availability for the Zeeland combined cycle units was lower due to the removal of the GSU
2 transformer for Zeeland Unit 5 and its replacement with the leased GSU transformer from
3 Zeeland Unit 1. Despite the slight decrease in MWh availability for these generating units,
4 the Company provided customer benefit in 2023. The Company quantifies this customer
5 benefit through Net Energy Value (“NEV”). At a high level, the NEV of a generating unit
6 is the difference between the market value of the energy produced and the cost of producing
7 and supplying that energy. The Company’s estimated 2023 NEV was \$225.7 million² as
8 compared to the 2022 amount of \$700.7 million, including the Company’s owned wind
9 assets, an amount which is directly attributable to MWh availability.

10 The Company’s 2023 base load fossil MWh availability decreased from 71.20% in
11 2022 (see MPSC Case No. U-21049, Exhibit A-13 (NJH-5), line 12, column (c)) to 63.99%
12 in 2023 (see Exhibit A-14 (NJH-5), line 13, column (c)), due to decreases in MWh
13 availability at Campbell Units 2 and 3, and Karn Unit 2. The primary cause of the drop in
14 the Company’s 2023 base load fossil MWh availability was the extended outage at
15 Campbell Unit 2, as previously discussed in this direct testimony, dropping the Campbell
16 Unit 2 MWh availability from 63.80% in 2022 to 38.70% in 2023.

17 **Comparison to GADS Data**

18 **Q. What is GADS?**

19 A. GADS is the Generator Availability Data System. NERC’s GADS maintains operating
20 histories for more than 5,000 generating units in North America. GADS is recognized as
21 a valuable source of reliability information for total unit and major equipment groups.
22 GADS contains information about the performance of electric generating equipment and

² The NEV calculation is based upon data pulled from PCI P&L actuals on January 16, 2024. The reduction in NEV from 2022 to 2023 was due to lower market prices in 2023 versus market prices in 2022.

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1 provides assistance to those researching information on power plant outages and supports
2 equipment availability analyses. GADS is a mandatory industry program for conventional
3 generating units 20 MW and larger.

4 **Q. Did you compare the availability of the Company's base load fossil units to GADS**
5 **data?**

6 A. Yes. I compared the availability of the Company's base load fossil units to both the 2022
7 and 2018 through 2022 GADS data for comparable sized and fueled units. The results are
8 shown on my Exhibit A-15 (NJH-6). The availability of Campbell Unit 3 was higher than
9 the five-year GADS data and the availability of Karn Unit 2 was higher than the one-year
10 GADs data. The availability of Campbell Unit 2, Campbell Unit 3, Karn Unit 1, and Karn
11 Unit 2 were below both the one-year and five-year comparisons.

12 **Q. Please explain the outages that contributed to lower-than-average availability on a**
13 **MWh basis.**

14 A. Campbell Unit 2 experienced a total of eleven outages during 2023: three maintenance,
15 and eight unplanned. The maintenance outages were taken for boiler tube leak repair,
16 reheater tube leak repair, ash pit trough repair, and turbine overspeed testing. The eight
17 unplanned outages resulted from a forced draft fan trip, a loss of auxiliary steam/steam
18 seals, a circuit oil cooler leak, and SUBFP failures.

19 Campbell Unit 3 experienced a total of seven outages during 2023: one planned,
20 two maintenance, and four unplanned. The planned outage was for replacement of a layer
21 of catalyst in the SCR vessel and repair of a suspected boiler waterwall leak. The
22 maintenance outages were for performance of the turbine safety required overspeed trip
23 test and resolution of #2 turbine bearing vibration issues. The four unplanned outages

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1 resulted from a drum level swing resulting in hot restart, required boiler leak repairs,
2 superheat tube leak repairs, and drum level swings after south side mills tripped due to a
3 breaker issue.

4 Karn Unit 1 experienced five outages during 2023: all unplanned outages. The five
5 unplanned outages were taken for coal leaks due to excessive pyrites, south upper intercept
6 valve stuck open, valve failure on the boiler circulating water pump, a faulty feedwater
7 control valve, and poor fuel quality/SO2 emission limited.

8 Karn Unit 2 experienced two outages during 2023: one maintenance outage and
9 one unplanned outage. The maintenance outage was taken to perform pre-retirement
10 cessation activities. The unplanned outage was for the repair of a boiler leak.

11 **Q. Did you review all of the outages shown on Exhibit A-10 (NJH-1)?**

12 A. Yes. I reviewed all the base load fossil and pumped storage outages that lasted longer than
13 24 hours.

14 **Q. In your opinion, did Consumers Energy act in a reasonable and prudent manner in**
15 **connection with the outages you reviewed on Exhibit A-10 (NJH-1)?**

16 A. Yes.

17 **NO_x Allowance Expenses**

18 **Q. Did Consumers Energy forecast NO_x expenses in the 2023 PSCR Plan case?**

19 A. No. Consumers Energy did not forecast NO_x expenses in the 2023 PSCR Plan case because
20 Selective Catalytic Reductions (“SCRs”) were installed and have significantly reduced
21 NO_x emissions and offset the need to purchase allowances. The SCRs were installed to
22 comply with the Clean Air Interstate Rule (“CAIR”), which was replaced by the
23 Cross-State Air Pollution Rule (“CSAPR”). CSAPR is a cap and trade rule much like

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CAIR. CSAPR governs the emission of SO₂ and NO_x from fossil-fueled electric generating units through the use of an allowance based “cap and trade” program. Under CSAPR, NO_x is regulated on both an annual basis and during the ozone season (May through September). Each allowance (annual or seasonal) permits the emission of one ton of NO_x, with the emissions cap and number of allocated allowances decreasing over time. SO₂ is regulated on an annual basis only, with the emissions cap decreasing over time. Phase I of CSAPR took effect on January 1, 2015 and Phase II became effective on January 1, 2017. In 2023, no allowance purchases were required for either the annual or seasonal requirements and there were no expenses associated with the allowances allocated by the Michigan Department of Environment, Great Lakes, and Energy.

Q. Did Consumers Energy receive revenue credits in 2023 related to the sale of NO_x allowances?

A. No. The Company did not sell NO_x emission allowances in 2023. As such, Company witness Leanna E. Feazel’s Exhibit A-5 (LEF-1) Revised does not reflect any expense or revenue credits for NO_x emission allowances.

SO₂ Allowance Expenses

Q. Did Consumers Energy incur expenses or receive revenue credits in 2023 related to the SO₂ Allowance Program?

A. Yes. Although the Company did not sell SO₂ emission allowances out of its inventory in 2023, it did receive revenue for a portion (\$60) of the Company-allocated SO₂ emission allowances during the annual US Environmental Protection Agency auction.

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1 **Q. Are the actual expenses and credits for SO₂ contained in Consumers Energy's 2023**
2 **Reconciliation?**

3 A. Yes. Company witness Feazel includes the actual SO₂ expenses and credits in Exhibit A-5
4 (LEF-1) Revised, line 20.

5 **Urea Expenses**

6 **Q. What was Consumers Energy's estimate of urea expenses for the 2023 PSCR Plan**
7 **case?**

8 A. Consumers Energy projected the cost of urea for 2023 to be \$4.145 million as reflected on
9 Exhibit A-17 (NJH-8), line 8, column (b), based on projected generation and SCR
10 operations at the Campbell Complex for Campbell Units 2 and 3.

11 **Q. What were the actual urea expenses?**

12 A. As reflected on Exhibit A-17 (NJH-8), line 8, column (c), actual urea expense for 2023 was
13 \$2.070 million, \$2.075 million lower than projected.

14 **Q. Why were actual urea expenses lower than projected?**

15 A. Urea expenses were lower than forecast as a result of lower than projected urea prices as
16 well as lower than projected generation. Urea prices are commodity based and are tied to
17 natural gas prices which experienced significant increases during 2022 but dropped back
18 down in 2023. The forecasted urea price was \$832/ton whereas the actual urea cost came
19 in at only \$563/ton. The extended outage at Campbell Unit 2 as well as the lower
20 availability at Campbell Unit 3 contributed to the remaining cost decrease.

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Aqueous Ammonia

Q. What was Consumers Energy's estimate of aqueous ammonia for the 2023 PSCR Plan case?

A. Consumers Energy projected the cost of aqueous ammonia for 2023 to be \$0.799 million as reflected on Exhibit A-17 (NJH-8), line 8, column (d), based on projected generation and SCR operations at Karn Units 1 and 2 and Zeeland Combined Cycle.

Q. What was the actual aqueous ammonia expense?

A. As reflected on Exhibit A-17 (NJH-8), line 8, column (e), actual aqueous ammonia expense for 2023 was \$1.449 million, \$0.650 million higher than projected.

Q. Why were actual aqueous ammonia expenses higher than projected?

A. Total actual aqueous ammonia expense for 2023 was higher due to the addition of Covert to the Company's fleet on June 1, 2023. Aqueous ammonia expenses for Karn Units 1 and 2 were slightly higher than forecast despite the fact that total generation was below that amount projected in the 2023 PSCR Plan, Case No. U-21257. The actual unit cost of aqueous ammonia for Karn Units 1 and 2 was approximately 5% higher than the average unit cost projected in the 2023 PSCR Plan, Case No. U-21257. In addition, with the shutdown of Karn Units 1 and 2 on May 31, 2023, not all of the aqueous ammonia delivered to the Karn site was utilized at the site; the unused quantity was utilized at Covert.

The aqueous ammonia expense for Zeeland was lower than projected due to the fact that the actual unit cost was almost 26% below the projected unit cost. In addition, the capacity factor for the Zeeland combined cycle units was lower than projected.

The aqueous ammonia expense for Covert was higher than projected as the projected aqueous ammonia expense was not reflected in the Company's 2023 PSCR Plan,

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Case No. U-21257. The addition of Covert to the Company's generation fleet was approved in the MPSC's June 23, 2022 Order in the Company's 2021 IRP, Case No. U-21090.

Lime

Q. What was Consumers Energy's estimate of lime expense in the 2023 PSCR Plan case?

A. Consumers Energy projected the cost of lime for 2023 to be \$8.205 million as reflected on Exhibit A-17 (NJH-8), line 8, column (f), based on projected generation and Spray Dry Absorber ("SDA") and Dry Sorbent Injection ("DSI") operations at the Karn and Campbell plants.

Q. What were the total actual lime expenses?

A. As reflected on Exhibit A-17 (NJH-8), line 8, column (g), actual lime expense for 2023 was \$7.761 million, \$0.444 million lower than projected. The Company consumes hydrated lime at Campbell Units 1 and 2 and consumes pebble lime at Campbell Unit 3 and Karn Units 1 and 2. The hydrated lime expense at Campbell Units 1 and 2 was 6.7% or \$0.295 million above forecast and the pebble lime expense at Campbell Unit 3 and Karn Units 1 and 2 was 19.6% or \$0.740 million below forecast.

Q. Why were the actual hydrated lime expenses higher than projected?

A. 2023 hydrated lime expenses were higher than projected for Campbell Units 1 and 2, primarily due to the quality of the coal delivered and consumed at Campbell Units 1 and 2, despite the lower than projected generation. Prior to 2022, most of the higher sulfur trains were being taken at Karn because it was easier to consume the higher sulfur coal at Karn than at Campbell Units 1 and 2 due to the challenges with removing SO₂ with their DSI system utilizing hydrated lime. The planned unit outage at Campbell Unit 3 in the spring

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of 2023 also increased the amount of higher sulfur coal that had to be consumed by Campbell Units 1 and 2 during 2022.

Q. Please discuss the actual pebble lime expense.

A. 2023 pebble lime expense was \$0.166 million lower for Karn Units 1 and 2 and \$0.574 million lower for Campbell Unit 3. The lower than projected capacity factors for Karn Units 1 and 2 and Campbell 3 was the primary reason for reduced pebble lime expense during 2023. In addition to the lower than projected capacity factor at Campbell Unit 3, the unit operated almost exclusively in “Recycle Mode” vs “Lime Only Mode” during 2023, and Lime Only Mode uses significantly more pebble lime than recycle mode.

Activated Carbon

Q. What was Consumers Energy’s estimate of activated carbon for the 2023 PSCR Plan case?

A. Consumers Energy projected the cost of activated carbon for 2023 to be \$2.271 million as reflected on Exhibit A-17 (NJH-8), line 8, column (h), based on projected generation and Activated Carbon Injection operations at Karn and Campbell.

Q. What were the actual activated carbon expenses?

A. As reflected on Exhibit A-17 (NJH-8), line 8, column (i), actual activated carbon expenses for 2023 were \$1.684 million, \$0.587 million lower than projected.

Q. Why were activated carbon expenses lower than projected?

A. The 2023 activated carbon expense was \$0.480 million lower than projected at the Campbell site due to lower-than-projected generation, the consumption of higher sulfur coal which generally contains less mercury, and better management of the operating limits for mercury.

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1 The 2023 activated carbon expense was \$0.106 million lower than projected at the
2 Karn site due to the fact that no new deliveries of activated carbon were made to Karn in
3 2023. The last delivery was made in December 2022 and was sufficient for remaining
4 plant operation in 2023.

5 **2023 Base Load Power Plant Generating Cost Efficiency**

6 **Q. Why was Exhibit A-10 (NJH-7) included in this filing?**

7 A. This information was provided in response to the MPSC's Report on Status of Power
8 Quality in Michigan in Case No. U-15945.

9 **Wind Asset Performance Data**

10 **Q. Please describe Exhibit A-18 (NJH-9).**

11 A. Exhibit A-18 (NJH-9) presents performance details regarding the Company's owned wind
12 assets. The Commission's September 28, 2023 Order in Case No. U-20803 required this
13 information to be included in future PSCR reconciliation proceedings. Specifically,
14 Exhibit A-18 (NJH-9) includes the 2023 gross actual generation, the 2023 actual and target
15 capacity factor, the 2023 actual and target time-based availability, and the 2023 lost
16 potential MWh due to planned maintenance, repair maintenance, and regulatory
17 curtailment.

18 **Q. Please describe Gross Actual Energy reflected in Exhibit A-18 (NJH-9), column (b).**

19 A. Gross Actual Energy is the gross volume of energy produced by a wind farm during a
20 specific period. The Gross Actual Energy does not represent any adjustment for station
21 power (amount of energy consumed by the wind farm during operations).

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1 **Q. Please describe capacity factor reflected in Exhibit A-18 (NJH-9), column (c).**

2 A. Capacity factor is the measure of how often a generation unit operates during a specific
3 period of time. Capacity factor is presented as a percentage and is calculated by dividing
4 the actual unit generation output by the maximum possible generation output. The
5 Company's target capacity factor is presented in Exhibit A-18 (NJH-9), column (d).

6 **Q. Please describe time-based availability reflected in Exhibit A-18 (NJH-9), column (e).**

7 A. Time-based availability is the measure of the hours during which the turbine is available
8 during a specific overall period of time. Time-based availability is presented as a
9 percentage, and 97% is generally considered first quartile performance in the industry. All
10 except one (which only narrowly missed this performance level) of the Company's parks
11 outperformed this high standard. The Company's targeted time-based availability and
12 actual availability is presented in Exhibit A-18 (NJH-9), column (f).

13 **Q. Please describe potential lost energy for planned and repair maintenance reflected in**
14 **Exhibit A-18 (NJH-9), columns (g) and (h).**

15 A. The potential lost energy for planned and repair maintenance is a calculation of how much
16 energy could have been generated during the periods in which the turbines were out of
17 service. The energy loss is only hypothetical because the calculation assumes sufficient
18 fuel (i.e. wind speed) would have been available for the turbines to operate during the time
19 frame in which they were unavailable for planned and repair maintenance, which in reality
20 would not always be true.

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1 **Q. Please describe lost energy for regulatory curtailment reflected in Exhibit A-18**
2 **(NJH-9), column (i)?**

3 A. Curtailment reflects the adjustment of the wind turbine blade angles (i.e. parallel to the
4 wind) to slow them down or stop them from turning (also known as “idling”). Wildlife
5 curtailment is implemented when the risk of collision is expected to be high for bird and
6 bat migration through the turbine sweep area, resulting in a reduction in bird and bat
7 collision fatalities. Icing curtailment may also be implemented for local special use permit
8 compliance reasons. The last reason for curtailment is possible implementation for energy
9 market reasons, this typically does not affect the Consumers Energy wind fleet, due to
10 primary dispatch as a “must run” resource.

11 **Q. Did the Company experience any asset failures during 2023?**

12 A. Yes. The Company experienced five pad-mounted transformer failures during 2023, four
13 at Gratiot Farms and one at Crescent wind. Three of the failures were unexpected, one
14 failure had high levels of gassing so the Company took it off-line as a preventative measure,
15 and the last pad-mounted transformer experienced a bushing failure and oil was leaking.
16 This final failure was discovered on rounds before it flashed over internally.

17 **Q. How did the Company manage these failures to minimize lost energy?**

18 A. In each of these cases after the failure occurred, tagging was set in place and site personnel
19 performed an inspection. Upon inspection, the pad-mounted transformer was bypassed,
20 and the rest of the circuit was brought back online minus one tower. Typically the balance
21 of the circuit was returned to service in less than 12 hours except for the turbine that
22 experienced the failure. Employing this methodology significantly reduced the amount of

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lost energy since it was usually a single turbine that was left out of service until the pad-mounted transformer replacement was accomplished and testing could be arranged.

Q. What other actions has the Company taken to minimize lost energy?

A. The Company established an inventory of spare pad-mounted transformers to ensure repair work could be accomplished in a more timely manner than could be achieved without the spare transformers. One of the factors that led to this decision is the fact that pad-mounted transformer delivery times have increased from 20-30 weeks to a full year.

In addition to the establishment of an inventory of spare pad-mounted transformers, the Company is performing quarterly rounds and is performing annual dissolved gas analysis testing. The Company believes that these practices allow for the early identification of a potential transformer failure and leads to more timely and less costly repairs. A summary of the 2023 failures is provided below.

Wind Asset	Pad-mounted transformer	Failure Date	Returned to service date
Crescent Wind	#55	11/9/2023	1/26/2024
Gratiot Farms	#49	1/4/2023	1/7/2023
Gratiot Farms	#42	1/19/2023	9/13/2023
Gratiot Farms	#4	2/7/2023	6/9/2023
Gratiot Farms	#27	3/18/2023	6/9/2023

Q. What is your assessment of the performance of the Company's wind generation assets during 2023?

A. Overall, the Company's wind assets exceeded their targeted time-based availability and, as a result, generated value for customers. Although the actual capacity factors fell short of target capacity factor, the wind generation fleet's exceedance of its time-based availability reflects the fact that the Company maintained its wind generation assets in a condition which would allow for creation of customer value.

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Ludington Replacement Power Costs

Q. Please discuss Exhibit A-19 (NJH-10) Revised.

A. Exhibit A-19 (NJH-10) Revised presents the 2023 Ludington outages which occurred as a result of defective work performed by TAES. The Company has removed replacement power expense associated with these outages from this reconciliation and has recorded these replacement power costs into a regulatory asset account that was established pursuant to the Commission's May 18, 2023 Order in Case No. U-21310. Specifically, this order approved the joint application of Consumers Energy and DTE Electric Company for cost deferral accounting and a regulatory asset for the costs incurred with remediating the defective work performed by TAES. In total, the Company has recorded into the regulatory asset account \$927,907 of replacement power costs incurred in 2023 as a result of defective TAES work. Company witnesses Hahn, Feazel, and Raymond T. Scaife reflect the removal of these replacement power costs in their direct testimony and exhibits.

Q. How did the Company identify Ludington unit outages that occurred as a result of defective work performed by Toshiba?

A. The Company documents its unit outages on the Ludington units and reports the outage information to GADS. To identify whether the outage should be evaluated for replacement power costs, the Company reviews the cause of the outage and the work performed. If the outage was caused by or related to required inspections and/or repairs of equipment which was subject to issues with Toshiba workmanship, the outage is attributed to Toshiba. In evaluating the cause of the outage and/or the work performed, the Company also considers whether the scope of normal planned maintenance activities has increased and resulted in extending normal maintenance outages.

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Conclusion

Q. Please provide a conclusion of your testimony.

A. My testimony described certain outages experienced in 2023 at the Company's fossil-fueled electric generating units and the Ludington Pumped Storage Plant, explained the expense associated with emission allowances for oxides of nitrogen and Sulfur Dioxide and explained the expense associated with the consumption of urea, aqueous ammonia, lime, and activated carbon. All generator outages were performed in a reasonable and prudent manner on the part of Consumers Energy. All expenses associated with emissions allowances and consumption of urea, aqueous ammonia, lime, and activated carbon were incurred in a reasonable and prudent manner. Finally, the Company's time-based availability for its wind generation fleet exceeded its plan.

Q. Does this conclude your direct testimony?

A. Yes.

Report Period: January 2023 to December 2023

CAMPBELL 1-2 - CAMPBELL 1							
Event	Type	Start	End	Cause	Description	Eq Hrs	Eq MWH
20	MO	3/7/2023 0:01	3/17/2023 23:59	1400	Economic Reserve Shutdown. Maintenance Outage 3/7 - 3/17. 1A FDF repair	262.97	68371.34
23	ME	3/17/2023 23:59	3/21/2023 1:01	1400	Economic Reserve Shutdown. 1A FD fan repairs	73.03	18988.67
24	MO	4/26/2023 10:41	4/26/2023 11:15	4460	Turbine overspeed tests.	0.57	147.33
25	U1	4/26/2023 11:15	4/28/2023 20:52	740	1C BCWP pump replacement	57.62	14980.33
41	U1	6/6/2023 5:09	6/7/2023 1:24	9900	U1 Tripped during simulated OS test portion of valve test.	20.25	5265
49	U1	6/23/2023 22:34	6/24/2023 21:57	250	1E feeder speed sensor failure, all other feeders hogged in, trip on drum lvl.	23.38	6079.67
56	U1	7/6/2023 21:56	7/15/2023 4:31	760	1D BCWP S. discharge valve large packing leak	198.58	51631.66
65	U1	7/24/2023 13:31	7/25/2023 6:07	310	1B mill capacitor failed during PMT, all feeders tripped causing MFT.	16.6	4316
66	U1	7/25/2023 9:22	7/25/2023 14:28	9900	low drum lvl trip, high throttle pressure	5.1	1326
81	U2	8/16/2023 19:06	9/5/2023 1:51	1000	boiler tube leak(s)	462.75	120315

CAMPBELL 1-2 - CAMPBELL 2							
Event	Type	Start	End	Cause	Description	Eq Hrs	Eq MWH
3	MO	1/3/2023 0:16	1/14/2023 13:32	1000	Maintenance Outage, boiler tube leak.	277.27	98429.66
16	U1	1/14/2023 14:06	1/14/2023 21:16	1400	FD fans tripped while automating.	7.17	2544.17
17	MO	1/15/2023 2:54	1/15/2023 5:23	4460	Turbine overspeed testing.	2.48	881.58
35	MO	3/6/2023 0:01	3/11/2023 0:26	1060	Economic Reserve Shutdown. MO 3/6 - 3/10. 1x RH tube leak. Ash pit trough repair	120.42	42747.91
38	U1	3/14/2023 18:21	3/15/2023 9:35	3831	Lost aux steam/steam seals.	15.23	5407.83
73	U1	5/16/2023 18:47	6/3/2023 7:48	640	201B packing leak, worse.	421.02	149460.92
107	U1	8/4/2023 20:35	8/10/2023 11:42	4291	Circuit oil cooler leak (water into the oil)	135.12	47966.42
108	U1	8/10/2023 13:39	9/29/2023 9:30	3401	SUBFP failure.	1195.85	424526.73
109	SF	8/10/2023 11:42	8/10/2023 13:39	3401	SUBFP failure.	1.95	692.25
110	SF	9/29/2023 9:30	9/29/2023 12:50	3401	SUBFP failure.	3.33	1183.33
111	U1	9/29/2023 12:50	1/1/2024 0:00	3401	SUBFP failure.	2244.17	796679.17

CAMPBELL 3 - CAMPBELL 3							
Event	Type	Start	End	Cause	Description	Eq Hrs	Eq MWH
67	U1	3/10/2023 10:32	3/10/2023 15:40	800	Unit trip due to drum level swing. Hot restart.	5.13	4319.19
98	PO	3/31/2023 16:47	5/10/2023 8:46	1000	Planned Outage. Boiler Tube leak repair. Catalyst replacement.	951.98	800998.78
111	U1	5/14/2023 18:59	5/30/2023 8:44	1035	Boiler leak. Unit in Forced Outage.	373.75	314473.25
112	MO	5/11/2023 8:21	5/11/2023 9:09	4460	Turbine Overspeed Test.	0.8	673.12
202	MO	7/7/2023 17:03	7/25/2023 10:37	4040	#2 Turbine bearing vibration issues.	425.57	357731.34
231	U1	8/28/2023 10:24	9/4/2023 4:56	800	Drum swing after south side mills tripped due to breaker issue.	162.53	136571.67
324	U1	11/20/2023 16:15	12/12/2023 19:52	1040	Superheat tube leak. Unit offline.	531.62	448094.5

**GENERATION PERFORMANCE STATISTICS
JANUARY 1, 2023 TO DECEMBER 31, 2023**

<u>Line No.</u>	(a)	(b)	(c)	(d)	(e)
	<u>Unit</u>	<u>Unit Availability</u>	<u>MWh Availability</u>	<u>Periodic Factor</u>	<u>Random Outage Rate</u>
1	Campbell 1	87.20%	81.34%	0.00%	18.66%
2	Campbell 2	49.50%	38.70%	9.33%	57.32%
3	Campbell 3 (CE)	72.02%	69.16%	10.87%	22.41%
4	Karn 1	72.07%	65.59%	3.77%	31.84%
5	Karn 2	74.66%	69.09%	5.33%	27.02%
6	Karn 3	52.02%	46.19%	11.46%	47.83%
7	Karn 4	80.70%	77.86%	4.07%	18.84%
8	Zeeland Simple Cycle	83.84%	77.97%	14.73%	8.56%
9	Zeeland Combined Cycle	78.09%	73.41%	11.86%	16.71%
10	Jackson CC	93.62%	85.75%	7.37%	7.43%
11	Covert CC	89.21%	83.30%	8.18%	9.28%
12	Total Fossil CE ¹	80.50%	74.58%	9.43%	17.65%
13	Base Load Fossil CE	70.39%	63.99%	6.26%	31.74%
14	Ludington 1-6	82.64%	80.58%	9.58%	10.88%
15	Total Hydro	78.60%	69.68%	15.48%	17.56%

¹ Does not include Karn 3 and Karn 4.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Midcontinent)
Independent System Operator)
(MISO))

Order No. 202-26-16

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 15

Hoffman 2025 Direct
Testimony

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
CONSUMERS ENERGY COMPANY)
for reconciliation of its power supply cost)
recovery plan (Case No. U-21423) for the)
12 months ended December 31, 2024.)
_____)

Case No. U-21424

DIRECT TESTIMONY

OF

NATHAN J. HOFFMAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

March 2025

NATHAN J. HOFFMAN
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1 **Q. Please state your name and business address.**

2 A. My name is Nathan J. Hoffman, and my business address is One Energy Plaza, Jackson,
3 Michigan 49201.

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

5 A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”)
6 as Executive Director – Fossil Generation.

7 **Q. Please describe your educational background.**

8 A. In 2003, I received a Bachelor of Science degree in Welding Engineering Technology from
9 Ferris State University. In 2017, I received a Master of Business Administration with a
10 concentration in Advanced Management Tools and Concepts from Ferris State University.

11 **Q. Please describe your business experience.**

12 A. In 2005, I joined Consumers Energy at the J.H. Campbell (“Campbell”) Generating
13 Complex and progressed through positions from Engineering Technical Analyst to the
14 Executive Director – Fossil Generation. In my various roles at Consumers Energy, I served
15 as a subject matter expert for boiler and piping systems and was an embedded engineering
16 resource in the Operations Department responsible for monitoring plant performance and
17 troubleshooting. I also planned and executed outages to ensure that they were performed
18 in a prudent and expeditious manner, as well as managed the site maintenance organization
19 tasked with maintaining the plant systems and equipment. As the Executive Director –
20 Fossil Generation, I have overall responsibility for the safe and excellent operations of the
21 Fossil Generation Fleet. In this role, I also manage the overall Operating and Maintenance
22 and Capital budgets, develop site specific staffing plans, develop strategies to meet
23 Company objectives, and instill a culture of continuous improvement. I further oversee

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the performance of the Site’s Operations, Maintenance, Fuel Handling, and Environmental and Technical Services departments.

Q. Have you previously provided testimony before the Michigan Public Service Commission (“MPSC” or the “Commission”)?

A. Yes, I provided testimony in the following MPSC Cases:

- Case No. U-21049: the Company’s 2022 Power Supply Cost Recovery (“PSCR”) Reconciliation Case;
- Case No. U-21257: the Company’s 2023 PSCR Plan Case;
- Case No. U-21423: the Company’s 2024 PSCR Plan Case;
- Case No. U-21258: the Company’s 2023 PSCR Reconciliation Case; and
- Case No. U-21592: the Company’s 2025 PSCR Plan Case.

Purpose of Direct Testimony

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

A. The purpose of my direct testimony is to:

- Describe the reasonableness and prudence of certain outages experienced in 2024 at the Company’s fossil-fueled electric generating units and the River Hydroelectric generating units (“River Hydros”);
- Describe the outages experienced in 2024 at the Company’s Ludington Pumped Storage Plant (“Ludington”), including the outages at Ludington resulting from defective, non-conforming, and incomplete work performed by Toshiba America Energy Systems Corporation (“TAES”), and the associated replacement power costs, which the Company has recorded to the regulatory asset approved by the Commission in Case No. U-21310;
- Explain the expense associated with emission allowances for oxides of nitrogen (“NO_x”) and Sulfur Dioxide (“SO₂”);
- Explain the expense associated with the consumption of urea, aqueous ammonia, lime, and activated carbon; and
- Explain the 2024 performance of the Company’s owned wind assets.

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1 **Q. Are you sponsoring exhibits with your direct testimony?**

2 A. Yes, I am sponsoring the following exhibits:

3 Exhibit A-11 (NJH-1) Event Summary Report, January 2024 to December
4 2024;

5 Exhibit A-12 (NJH-2) Event Identification – Outages;

6 Exhibit A-13 (NJH-3) Periodic Outage Reports;

7 Exhibit A-14 (NJH-4) 2024 Fossil and Pumped Storage Outages Occurring
8 for Twenty-Eight Days or More;

9 Exhibit A-15 (NJH-5) Generation Performance Statistics (January 1, 2024
10 to December 31, 2024);

11 Exhibit A-16 (NJH-6) Comparison of Consumers Energy and Generating
12 Availability Data System (“GADS”) Averages for
13 Similar Units Equivalent Availability;

14 Exhibit A-17 (NJH-7) 2024 Base Load Generation Power Plant Cost
15 Efficiency;

16 Exhibit A-18 (NJH-8) Chemical Reagent Expense (January 1, 2024 to
17 December 31, 2024);

18 Exhibit A-19 (NJH-9) 2024 Wind Asset Performance Data;

19 Exhibit A-20 (NJH-10) 2024 Ludington Outages; and

20 Exhibit A-21 (NJH-11) Campbell Unit 2 Outage Pre-Start Check Sheet.

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

22 A. Yes.

23 **2024 Outages**

24 **Q. Have you provided a listing of all 2024 outages?**

25 A. Yes. The Event Summary Report, Exhibit A-11 (NJH-1), lists all unit outages and trips.
26 The report shows 17 events on the coal units; 98 on the Ludington Units; 71 collectively
27 on the Zeeland Combined Cycle Plant (“Zeeland CC”) (Units 3, 4, and 5), Covert Gas Plant
28 (“Covert”), and Jackson Gas Plant (“Jackson”); 22 on D.E. Karn (“Karn”) Units 3 and 4;

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1 17 on the Zeeland Simple Cycle (“Zeeland SC”) (Units 1 and 2); and 640 on the River
2 Hydro units. The total number of outage events for the fleet was 865,441 more than in
3 2023, and 342 more than in 2022. This increase in outages events was due to the increase
4 in River Hydro events, discussed later in this testimony. Excluding the River Hydro events,
5 the outage events total would in fact be lower than both 2023 and 2022, at just 225 outages.

6 Exhibit A-11 (NJH-1) provides a description of each event, including the event start
7 time, event end time, cause code,¹ duration in equivalent hours, and equivalent MWh. The
8 equivalent MWh calculation assumes that the units would have operated at 100% capacity
9 factor.

10 **Q. Has the Company also calculated the lost generation for the Ludington Units in**
11 **accordance with the Settlement Agreement approved in the Commission’s June 28,**
12 **2018 Order in Case No. U-17918-R?**

13 A. Yes. Company witness Sarah K. Seng provides the economic MWh loss calculations for
14 the Ludington Units assuming they were operating and dispatchable. These calculations
15 are presented in Exhibit A-27 (SKS-3).

16 **Q. Would you please define the words “outage,” “trip,” and “event”?**

17 A. A unit “outage” on a base-load unit is defined as the period from when the circuit breaker
18 opens, separating the unit from the electric system, to when it closes, tying the unit to the
19 electric system and making it available for dispatch, and the unit is not in economic reserve
20 status. A unit “outage” on a cycling or peaking unit is defined as the period from when the
21 Company’s Electric Supply Operations Department releases a unit, making it unavailable,

¹ Cause codes used are taken from the Data Reporting Instructions of the North American Electric Reliability Corporation (“NERC”) Generating Availability Data System. Explanations for the cause codes can be found at: Data Reporting Instructions (nerc.com)

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1 to when the plant reports to Electric Supply Operations that the unit is available for service.
2 For the purposes of these definitions, the coal and river hydro units are considered
3 base-load units, and the Zeeland, Jackson, Covert, and Karn Units 3 and 4 are all considered
4 cycling units. Zeeland Units 1 and 2 are considered peakers. Base load generation refers
5 to the minimum amount of electric power required to be delivered to customers over a
6 given period of time at a steady rate. Base load generating units are units which are
7 typically operated to serve customer loads on an around-the-clock basis.

8 A “trip” is a unit outage that begins when protective devices automatically separate
9 a unit from the electric system, or the operator initiates a manual and immediate separation.
10 This is in contrast to the normal controlled shutdown process where operators may spend
11 several hours slowly reducing pressure and load before separating the unit from the system.

12 An “event” is a one-line entry on the Event Summary Report. Each line on the
13 Report contains an outage “event.” The outage event classification is divided into eight
14 distinct event types: (i) Planned Outage; (ii) Maintenance Outage; (iii) Planned Outage
15 Extension; (iv) Maintenance Outage Extension; (v) Startup Failure; (vi) Unplanned
16 (Forced) Outage-Immediate; (vii) Unplanned (Forced) Outage-Delayed; and
17 (viii) Unplanned (Forced) Outage-Postponed. Exhibit A-12 (NJH-2) explains the different
18 types of outages shown on Exhibit A-11 (NJH-1).

19 **Q. Have you documented outage occurrences in more detail?**

20 A. Yes. In addition to documenting all of the 2024 outages reported on page 3 of this
21 testimony and reflected in Exhibit A-11 (NJH-1), outage information sheets were also
22 prepared for generating units that had lower availability averages than those shown in
23 GADS data discussed later in my direct testimony. The information sheets are provided as

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Exhibit A-13 (NJH-3). Each sheet contains the same statistical data found on Exhibit A-11 (NJH-1), as well as: (i) an expanded description of the event; (ii) a cause of the event; (iii) the work that was done to correct the root cause for forced outages or the work that was performed during maintenance and periodic outages; (iv) other work, if any, that was performed; (v) a description of work that extended the outage, if any extension occurred; and (vi) why that work was performed.

Additionally, the Company prepared a Periodic Outage, Maintenance Outage, or Forced Outage Information sheet for each of the events lasting 28 days or more on the fossil, pumped storage, peaking, and River Hydro units shown on Exhibit A-11 (NJH-1).

Q. Before discussing specific outages, do you have any general comments about outages in the Company's generation fleet?

A. Yes, particularly concerning the Company's older units. Some of these units were built in the 1960s, and given the ages and designs of the systems, replacement parts are not always readily available. In some instances, replacement parts do not exist at all. The start-up boiler feed pump ("SUBFP") at Campbell Unit 2 is one of those systems. Keeping spare parts on hand is neither cost effective nor practical since replacements do not exist.

Fossil, Cycling, and Pumped Storage Outages Planned for 28 Days or More

Q. In Case No. U-21423, how many outages were planned for 28 days or more?

A. My direct testimony and Exhibit A-10 (NJH-1) in that case identified nine such outages.

Q. Were all nine outages completed during the plan year?

A. Yes, however, only eight of the planned outages lasted 28 days or more.

Q. Which outage had a shorter outage duration and why?

A. The Ludington Unit 3 outage was originally scheduled for a 47-day duration; however, the outage was able to be reduced to 27 days, starting on October 30, 2024 and concluding

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November 26, 2024. A portion of this outage was associated solely with defective, non-conforming, and incomplete work by TAES. The portion of the replacement power costs related to this work was removed to the regulatory asset approved by the Commission in Case No. U-21310 and included in Exhibit A-20 (NJH-10). TAES-related outages are discussed later in my testimony.

Q. Did the Company conduct additional outages of 28 days or more in 2024?

A. Yes. In addition to the eight planned outages which lasted longer than 28 days, the Company conducted seven additional outages for a total of fifteen outages that lasted 28 days or more. The additional outages included Ludington Unit 4, Ludington Unit 5, Ludington Unit 6, Covert Unit 2, Karn Unit 3, and two outages at Karn Unit 4. All fifteen outages are identified in Exhibit A-14 (NJH-4).

Q. Has your review of the outages listed in Exhibit A-14 (NJH-4) led you to a conclusion concerning these outages?

A. Yes. I have concluded that all of the outages listed in Exhibit A-14 (NJH-4) were carefully planned, prudently managed, and free of negligence on the part of Consumers Energy as to either causation or extension of outage time. Below is a brief summary of each of the outages listed in Exhibit A-14 (NJH-4).

Campbell Unit 1

The Campbell Unit 1 outage began on March 1, 2024, and lasted 30 days, concluding March 31, 2024. This planned outage was for routine valve maintenance and to address governor valve instability at lower loads. Additional maintenance tasks included explosive backpass cleaning and the installation of a 1D boiler circulating water pump. All of which was necessary to maintain unit reliability.

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Campbell Unit 2

The Campbell Unit 2 outage began on August 4, 2023 due to a tube leak in the hydraulic coupling circuit oil cooler. The tube leak resulted in water intrusion into the oil system, thereby forcing the unit to be removed from service. Subsequently, on August 10, 2023, the SUBFP experienced a thrust event causing damage to the internal flow element, thrust bearing, and drive coupling. The unit was out of service for the remainder of 2023 and the first 101 days of 2024, concluding on April 10, 2024. A detailed discussion of the extended outage is provided later in this direct testimony.

Campbell Unit 3

The outage at Campbell Unit 3 was scheduled to begin April 1, 2024 and was projected to last for 30 days – concluding May 1, 2024. The outage began on April 12, 2024 and lasted 61 days, instead of the planned 30 days, and concluded on June 12, 2024. The outage began as a maintenance outage to repair tube leaks. The outage was extended due to a failed turbine turning gear upon startup. During the outage, it was found that the teeth in the planetary gear assembly had been sheared off, due to assumed cyclic fatigue. The turning gear assembly was last inspected in 2016, with no findings. Planetary gears and drive shaft replacement was performed to allow the unit to resume operation until the planned retirement in May of 2025.

Karn Unit 3

The outage at Karn Unit 3 began on May 3, 2024 and lasted 29 days, concluding May 31, 2024. This outage was a spring outage to repair a known boiler water wall leak, sectionalized replacement of sections BB and BC of combustion air heater, inspection of

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1 the deaerator heater and storage tank, and inspection and certification of boiler code safety
2 relief valves.

3 **Karn Unit 4**

4 The first outage at Karn Unit 4 began on April 20, 2024 and lasted 31 days,
5 concluding May 20, 2024. This outage was a periodic outage to perform six-year safety
6 inspections of the Deaerator and Deaerator Heater and Storage Tank (“DAST”). During
7 the inspection, it was found necessary to replace the obsolete deaerator heater’s five safety
8 relief valves due to parts being unavailable. Associated balance of plant repairs were also
9 completed.

10 The second outage at Karn Unit 4 began on October 28, 2024 and lasted 31 days,
11 concluding on November 27, 2024. This outage was for High Voltage Distribution
12 (“HVD”) lines and Sync Wire replacement. Due to expanded requirements for the Ash
13 Field caps beyond the original design, there was interference caused between the ground
14 elevation and the wire placement, requiring the transmission lines to be raised. During this
15 outage, additional work was performed including a boiler water wall tube leak repair,
16 balance of plant work, and Karn Unit 4 steam strainer seal replacement.

17 **Ludington Unit 1**

18 The outage at Ludington Unit 1 began on February 12, 2024 and lasted 40 days,
19 concluding March 22, 2024. This outage was scheduled for three-year maintenance
20 activities. The Company also took the opportunity afforded by the outage to facilitate
21 litigation-related inspections demanded by TAES and its parent company, Toshiba
22 Corporation, pertaining to Consumers Energy’s and DTE Electric Company’s (“DTE”) ongoing
23 lawsuit against those parties. The litigation-related inspections did **not** require an

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1 extension to the outage. Maintenance work performed during the outage included repair
2 on cavitation damage on wicket gates, which was found during inspections, along with
3 lower end seal replacements of five of the wicket gates. Because the outage would have
4 been the same length regardless of TAES-related defects, the replacement power costs
5 associated with the outage were not removed to the regulatory asset approved by the
6 Commission in Case No. U-21310. Additional discussion on TAES-related outages can
7 be found later in my testimony.

8 **Ludington Unit 2**

9 The outage at Ludington Unit 2 was scheduled to begin, February 12, 2024, and
10 last for 40 days. Instead, the outage began on February 1, 2024, but still lasted 40 days,
11 concluding on March 15, 2024. This outage was scheduled for three-year maintenance
12 activities. The Company also took the opportunity afforded by the outage to facilitate
13 litigation-related inspections demanded by TAES and its parent company, Toshiba
14 Corporation, pertaining to Consumers Energy's and DTE's ongoing lawsuit against those
15 parties. The litigation-related inspections did **not** require an extension to the outage. Work
16 performed during the outage included certain typical nine-year outage activities,
17 inspections on the generator and transformer, and cleaning of the generator air coolers.
18 Because the outage would have been the same length regardless of TAES-related defects,
19 the replacement power costs associated with the outage were not removed to the regulatory
20 asset approved by the Commission in Case No. U-21310. Additional discussion on
21 TAES-related outages can be found later in my testimony.

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Ludington Unit 4

The outage at Ludington Unit 4 began on October 23, 2024 and lasted 29 days, concluding November 20, 2024. This was an annual periodic outage to perform Main Transformer Bank (“MTB”) #2 Electrical inspections, Turbine Lube Oil Cooler maintenance, and Wicket Gate Thrust Collar inspections. During this outage, additional work was completed including Turbine Runner Cavitation and Wicket Gate Cavitation repairs, 416 pumping pole replacement, and MTB Isophase Bus Inspections. A portion of this outage was associated solely with defective, non-conforming, and incomplete work by TAES. The portion of the replacement power costs related to this work was removed to the regulatory asset approved by the Commission in Case No. U-21310 and included in Exhibit A-20 (NJH-10). TAES-related outages are discussed later in my testimony.

Ludington Unit 5

The outage at Ludington Unit 5 began January 29, 2024 and lasted 74 days, concluding April 11, 2024. This outage was required to facilitate litigation-related inspections demanded by TAES and its parent company, Toshiba Corporation, pertaining to Consumers Energy’s and DTE’s ongoing lawsuit against those parties. While the unit was down as a result of the litigation demand, additional work was performed, including inspections of the spiral case, turbine runner, MTB #3 oil addition and inspections. During the inspection of turbine runner blade, a crack was identified at the attachment weld between the turbine runner band and a turbine blade. The recommendation was to repair prior to returning to operation to avoid the risk catastrophic damage, which led to the extension of this outage. The damaged weld interface and subsequent base metal was cut out and then rebuilt with weld repair. The cause of this crack was found to be due to high

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1 stress intensification at the interface between the turbine runner band casting and a turbine
2 blade due to internal weld defects and excessive weld root porosity during original
3 manufacturing. Because the outage was scheduled to address Toshiba-related defective
4 work, and then extended due to the need to repair Toshiba defects, the replacement power
5 costs were removed to the regulatory asset approved by the Commission in Case No.
6 U-21310, as shown in Exhibit A-20 (NJH-10). Additional discussion on TAES-related
7 outages can be found later in my testimony.

8 **Ludington Unit 6**

9 The outage at Ludington Unit 6 began September 30, 2024 and lasted 30 days,
10 concluding October 29, 2024. This was a schedule periodic outage for the purpose of
11 MTB #3 Electrical inspections, turbine lube oil cooler maintenance, and Wicket Gate
12 Thrust Collar inspections. During this outage, additional work was completed including
13 Turbine Runner Cavitation and Wicket Gate Cavitation repairs, Pony Motor #2 inspections,
14 and South Trash Rack repairs. A portion of this outage was associated solely with
15 defective, non-conforming, and incomplete work by TAES. The portion of the replacement
16 power costs related to this work was removed to the regulatory asset approved by the
17 Commission in Case No. U-21310 and included in Exhibit A-20 (NJH-10). TAES-related
18 outages are discussed later in my testimony.

19 **Covert Unit 2**

20 The outage at Covert Unit 2 began on May 6, 2024 and lasted 40 days, concluding
21 June 14, 2024. It was a periodic outage for routine borescope inspections and repairs for
22 continued reliable operation. This work included performing Selective Catalytic Reduction
23 (“SCR”) catalyst inspection and cleaning, annual calibration of the unit’s fuel gas valves,

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1 inspection of the Heat Recovery Steam Generator (“HRSG”) flue gas pass, replacement of
2 the bearing and seals on the 2B ammonia injection fan, Gas Turbine borescope inspection,
3 Gas Turbine overspeed testing, and balance of plant inspections and repairs. Additionally,
4 during the outage, field balancing was attempted to reduce unacceptable levels of vibration
5 in the pump during operation, caused by an unbalanced impeller. The bearings, sleeve,
6 and impeller rings were also replaced. Exiting the outage, the pump experienced a step
7 change increase in vibrations requiring the pump to be pulled and sent for an overhaul,
8 before being restored to operation.

9 **Zeeland Units 3, 4, and 5**

10 The outages at Zeeland Units 3, 4, and 5 were all scheduled to begin on May 19,
11 2024 and last 28 days, concluding June 16, 2024. The outages on all three units began
12 September 20, 2024 and lasted 40 days, concluding October 30, 2024. These outages were
13 necessary for the installation of the overhauled Unit 5 transformer and removal of the rental
14 transformer. While the units were down, additional work was performed including
15 replacement of main stream non-return valves and replacement of HRSG ductwork panels,
16 due to thinning. Upon initial energization, excessive internal gassing² was observed,
17 causing a preemptive shut down to all three units. Additional operation has shown that
18 dissolved gas production has subsided, and both Company and external experts,
19 recommend continuing to operate the transformer and closely monitoring for any change
20 in dissolved gas levels. If after six months there is no change in the dissolved gas levels,

² Internal gassing can be explained as the breakdown of transformer oil due to the presence of high level of heat within the transformer. This ‘gassing’ is the residual product of this oil breakdown and is routinely monitored to determine transformer health and to prevent the excessive accumulation of combustible gasses within the transformer that could pose a threat to its integrity and long-term life.

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1 the main transformer oil will be changed, and the transformer will be considered in a
2 satisfactory state.

3 **Q. Did the Company conduct any outages that exceeded 90 days in duration?**

4 A. Yes. The Company had one outage during 2024 that exceeded 90 days in duration, which
5 was the Campbell Unit 2 outage which lasted for 101 days during 2024.

6 **Q. Why did the Campbell Unit 2 outage exceed 90 days?**

7 A. As previously discussed in this direct testimony, as well as both the direct testimony and
8 rebuttal testimony in Case No. U-21258, the Campbell Unit 2 outage began on August 4,
9 2023, because of a tube leak in the hydraulic coupling circuit oil cooler which resulted in
10 water intrusion into the oil system, thereby forcing the unit to be removed from service.
11 After the tube leak repair, during post-maintenance testing on August 10, 2023, the SUBFP
12 experienced a thrust event, which resulted in damage to the SUBFP internal flow element,
13 thrust bearing, and drive coupling.

14 **Q. What was the root cause of the thrusting event?**

15 A. The Company conducted thorough evaluations of the thrusting event and narrowed the root
16 cause to two possibilities. The two potential root causes that could have led to the event
17 were (1) seal water injection that was not sufficiently getting through the pump seals and
18 (2) the SUBFP having non-compressible gasses (an air bubble) trapped in the pump. While
19 the Company's thorough evaluation of each of these potential causes of the thrusting event
20 did consider operator error, it did not identify any errors performed by the Company which
21 may have led to the outage.

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1 **Q. Has the Company experienced additional instances of inadequate lubrication of the**
2 **seals with the seal water?**

3 A. Yes. During the period from August 2023 through March 2024, the Company made
4 multiple observations of erratic seal water pressure. The pressure control valve, pressure
5 control valve controls, associated piping, and seal water filters were all inspected to
6 determine a cause of the erratic pressure control with no causes identified.

7 **Q. What measures does the Company have in place to ensure the system is purged of any**
8 **potential trapped gases?**

9 A. Purging of potential trapped gases is performed on a routine basis by well-trained operators
10 and is basic operator knowledge. In this instance, as is customary before purging, a pre-job
11 brief was held during which the activities to be performed were discussed. Upon
12 completion of the purging activity, the operator confirmed completion of this activity on
13 the prestart check-sheet, as shown on step 10 in Exhibit A-21 (NJH-11), which includes
14 instructions to “[h]ave the SUBFP vented.”

15 **Q. In your opinion, did the actions of anyone at the Company cause this outage?**

16 A. No. If anything, the actions of the operators at Company prevented a catastrophic failure
17 of the unit. Following the reassembly of the pump in 2024, multiple attempts to operate
18 the pump and commence startup were made. As stated in my earlier testimony,
19 observations were made that indicated there was an issue with injection seal water pressure
20 which was resolved through increasing the injection seal water pressure. Along with the
21 resolution of the injection seal water pressure, the pump continued to operate with elevated
22 vibration levels which was ultimately determined to be excited by the spare “Kopflex”
23 coupling that was used as part of the rebuild from the August 2024 thrust event. At the

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1 time of rebuild, the only coupling available for use was a spare “Kopflex” coupling that
2 was kept in stock. The original coupling, a Goodrich brand coupling made from titanium,
3 was damaged as a result of the thrust event. The spare Kopflex coupling represents
4 approximately a 67.5-pound increase in weight over the original Goodrich titanium
5 coupling. Vibration velocity levels observed at the initial startup following the rebuild
6 were as high as 1.0 inch per second on the outboard end of the pump and 0.8 inches per
7 second on the inboard end of the pump, which were deemed unsafe to operate. Based on
8 these observations, the Company worked diligently with vendors to study the vibration of
9 the pump and design and install dynamic vibration absorbers to counteract the effect of the
10 increase in mass of the Kopflex coupling. In parallel, efforts were made to procure a new
11 Goodrich titanium coupling as well as engineering coupling hubs made of titanium to
12 reduce the overall mass of the coupling assembly. In addition, the Company worked with
13 coupling manufacturers to design and manufacture a new lighter coupling. Ultimately, the
14 re-engineering of the coupling hubs utilizing titanium was enough to reduce the vibration
15 within acceptable levels – 0.5 inches per second or below.

16 **Q. Have you reviewed the peaker and hydro unit outages?**

17 A. Yes. I reviewed the events for each peaker and hydro unit shown on the Event Summary
18 Report, Exhibit A-11 (NJH-1). There were no peaker outages that lasted longer than
19 28 days in 2024.

20 River hydro outages greater than 28 days are summarized in the table below,
21 including events in which there was a lack of sufficient water to run the unit. The
22 Company’s hydro units that are considered run of river plants, do not store water, but rely
23 on the natural flow of the river to operate. Effective 2024, the North American Electric

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1 Reliability Corporation (“NERC”) updated its Special Hydro Reporting Guidance with
2 new reporting procedures. One such change is the classification of an outage due to lack of
3 river flow. Per NERC guidelines,³ “When a unit must be shut down because there is
4 insufficient water to run all the units and there is no reservoir that would allow the units to
5 run if called upon,” these are to be categorized as U3 - Forced outage due to insufficient
6 river flows, with a cause code of 9135 - Lack of Water. Due to these updated reporting
7 requirements, the Company saw a significant increase in outage events.

³ Guideline definition taken from the [Hydro Assets Special Hydro Reporting Guidance](#) presentation from of the North American Electric Reliability Corporation (“NERC”) GADS Data Reporting Training Workshop.

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Hydro Unit	Actual Days in 2024	Event Number(s)
Alcona 1	100	3&4
Alcona 2	65	2
Alcona 2	35	11
Allegan 1	32	4
Allegan 1	212	5
Allegan 2	60	1 & 9
Cooke 1	52	8 & 27
Cooke 2	45	7 & 15
Cooke 3	63	33
Croton 1	31	1
Croton 1	50	2 & 5
Croton 2	31	1 & 6
Croton 2	46	8 & 9
Croton 3	128	2 & 3
Croton 3	36	12 & 14
Croton 4	108	2
Five Channels 1	29	5
Five Channels 1	64	18
Foote 1	49	3 & 7
Foote 1	36	5
Foote 1	35	17 & 18
Foote 2	58	11
Hardy 1	38	1, 11, 12
Hodenpyl 1	338	1 & 2
Loud 1	34	29
Loud 2	36	12
Loud 2	42	23
Mio 1	37	1 & 6
Mio 1	69	17
Mio 1	42	18, 19, 20
Mio 2	37	11
Rogers 1	233	3
Rogers 2	233	3 & 1
Rogers 3	124	1 & 5
Rogers 3	114	4
Rogers 4	128	1
Rogers 4	114	6
Tippy 1	366	1
Tippy 3	41	17
Tippy 3	50	20
Webber 1	70	5
Webber 2	51	1
Webber 2	38	9 & 2

My review of these events and the additional information provided on Exhibit A-13 (NJH-3) leads me to conclude that those outages were conducted in a prudent manner.

Outages with a Duration of Fewer Than 28 Days

Q. How many periodic outages less than 28 days but greater than one day in length occurred on the fossil and Ludington Units in 2024?

A. As shown on Exhibit A-11 (NJH-1), 30 short periodic (planned) outages occurred on the fossil and Ludington Units in 2024.

Q. What was the purpose of these periodic outages?

A. In general, the purpose of these outages was to perform preventative maintenance activities on equipment that has been assessed as being non-functional or having gone more than one to two years without preventative or corrective maintenance.

Availability

Q. Please discuss the Company's 2024 generation unit availability.

A. The Company's 2024 generation unit availability data is shown on Exhibit A-15 (NJH-5). The Company's Total Fossil MWh availability slightly increased from 74.58% in 2023 (see Case No. U-21258, Exhibit A-14 (NJH-5), line 12, column (c)) to 78.99% in 2024 (see Exhibit A-15 (NJH-5), line 10, column (c)) due to increases in MWh availability at Campbell Units 2 and 3, Karn Unit 3, Jackson Gas Plant, and the Zeeland combined cycle units. Despite the slight decrease in MWh availability at the Campbell Unit 1, Karn Unit 4, and Covert generating units, the Company provided customer benefit in 2024. The Company quantifies this customer benefit through Net Energy Value ("NEV"). At a high level, the NEV of a generating unit is the difference between the market value of the energy produced and the cost of producing and supplying that energy. The Company's estimated 2024 NEV was \$312.7 million⁴ as compared to the 2023 amount of \$225.7 million,

⁴ The NEV calculation is based upon data pulled from PCI P&L actuals on February 5, 2025.

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1 including the Company's owned wind assets, an amount which is directly attributable to
2 MWh availability.

3 The Company's 2024 base load fossil MWh availability increased from 63.99% in
4 2023 (see MPSC Case No. U-21258, Exhibit A-14 (NJH-5), line 13, column (c)) to 73.18%
5 in 2024 (see Exhibit A-15 (NJH-5), line 11, column (c)) due to increases in MWh
6 availability at Campbell Units 2 and 3, and Karn Unit 3, Jackson Gas Plant, and Zeeland
7 Units.

8 **Q. Did the Covert Units experience issues that affected their availability?**

9 A. Yes. The Covert units experienced issues with circulating water pumps on each of the
10 three units that resulted in failures of pumps or resonant frequency vibration issues. Each
11 Covert unit has two circulating water pumps that circulate water from the condenser to the
12 cooling towers. Depending on ambient conditions, a unit may experience a derate when
13 one of the circulating water pumps is out of service. The Company has been working with
14 the pump's original equipment manufacturer as well as other pump maintenance vendors
15 to identify the potential causes of the pump failures and excessive vibration. In working
16 with our vendors, the Company has identified modifications that have been made to a pump
17 that will be installed during the Covert Unit 2 Spring 2025 outage. The performance of the
18 modified pump will be studied to determine if the same modification should be made on
19 the other pumps. Additionally, any time a pump fails and must be pulled from its pit, a
20 unit outage is required.

21 The Covert Generating site also experienced impacts to availability due to stack
22 particulate matter ("PM") testing results as part of the five-year renewable operating permit
23 testing requirements. Gas generation sites utilize EPA Method 5/202 for identifying the

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quality of condensable PM emitted from a stack. While EPA Method 5/202 is an approved test method, this method is not well suited for testing very low PM concentrations due to inherent limits of the method that can lead to high bias and uncertainty. When coupled with very low permit limits, this testing can yield high biased results that lead to a permit exceedance even though no apparent source of particulates in the operating unit can be identified. In the case of Covert Units 1 and 3, PM testing results indicated an exceedance of the unit's air permit limits. As a result, units were removed from service out of an abundance of caution until the test data could be validated. The Company worked to identify the maximum amount of heat input at which the units could be operated while not violating permit requirements to return to service until additional testing plans could be developed. Through extensive causal analysis, it was determined that there were no operational abnormalities contributing to the excessive PM test results; rather, inconsistencies and bias with the testing method led to the erroneous concentration results.

Lastly, Covert Unit 3 was removed from service due to quench cracking located in one of the circumferential welds in the reheat cross over pipe. The root cause of quench cracking was due to failure of the reheat attemperator spray nozzle. Failure of the spray nozzle allowed for the creation of a flow path for attemperator water to leak behind the attemperator liner and cause the quench cracking of the circumferential weld. During the outage, the section of reheat cross over piping and attemperator assembly was replaced.

Comparison to GADS Data

Q. What is GADS?

A. GADS is the Generator Availability Data System. NERC's GADS maintains operating histories for more than 5,000 generating units in North America. GADS is recognized as

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1 a valuable source of reliability information for total unit and major equipment groups.
2 GADS contains information about the performance of electric generating equipment and
3 provides assistance to those researching information on power plant outages and supports
4 equipment availability analyses. GADS is a mandatory industry program for conventional
5 generating units 20 MW and larger.

6 **Q. Did you compare the availability of the Company's base load fossil units to GADS**
7 **data?**

8 A. Yes. I compared the availability of the Company's base load fossil units to both the 2023
9 and 2019 through 2023 GADS data for comparable sized and fueled units. The results are
10 shown on my Exhibit A-16 (NJH-6). The availability of Campbell Units 1 and 3 was higher
11 than the one-year GADs data. The availability of Campbell Unit 2 was below both the
12 one-year and five-year comparisons. The availability of Campbell Units 1, 2, and 3 were
13 all below the five-year comparisons.

14 **Q. Please explain the outages that contributed to lower-than-average availability on a**
15 **MWh basis.**

16 A. Campbell Unit 1 experienced a total of four outages during 2024, one of which lasted
17 38 days and is discussed in greater detail earlier in my direct testimony. Additional outages
18 included turbine overspeed testing, 1C coal pulverizer feed issue that resulted in 20 MW
19 load swings causing the unit to trip, and a super heat tube leak.

20 Campbell Unit 2 experienced a total of seven outages during 2024, one being the
21 SUBFP outage discussed in detail earlier in this direct testimony, and six other unplanned
22 outages, including circuit oil cooler leaks, a turbine valve issue when it closed unexpectedly
23 causing boiler overpressure and the unit tripped, a leak on thrust oil protective trip device,

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1 a forced outage due to a broken pin rack on the 2B secondary air heater and left, turbine
2 throttle valve steam leak, and another forced outage to address 201A and 210 valves.

3 Campbell Unit 3 experienced a total of two outages during 2024: one planned
4 maintenance outage to repair a tube leak and one unplanned due to a turbine turning gear
5 failure.

6 **Q. Did you review all of the outages shown on Exhibit A-11 (NJH-1)?**

7 A. Yes. I reviewed all the base load fossil and pumped storage outages that lasted longer than
8 24 hours.

9 **Q. In your opinion, did Consumers Energy act in a reasonable and prudent manner in**
10 **connection with the outages you reviewed on Exhibit A-11 (NJH-1)?**

11 A. Yes.

12 **NO_x Allowance Expenses**

13 **Q. Did Consumers Energy forecast NO_x expenses in the 2024 PSCR Plan case?**

14 A. No. Consumers Energy did not forecast NO_x expenses in the 2024 PSCR Plan case because
15 SCRs were installed and have significantly reduced NO_x emissions and offset the need to
16 purchase allowances. The SCRs were installed to comply with the Clean Air Interstate
17 Rule ("CAIR"), which was replaced by the Cross-State Air Pollution Rule ("CSAPR").
18 CSAPR is a cap and trade rule much like CAIR. CSAPR governs the emission of SO₂ and
19 NO_x from fossil-fueled electric generating units through the use of an allowance based "cap
20 and trade" program. Under CSAPR, NO_x is regulated on both an annual basis and during
21 the ozone season (May through September). Each allowance (annual or seasonal) permits
22 the emission of one ton of NO_x, with the emissions cap and number of allocated allowances
23 decreasing over time. SO₂ is regulated on an annual basis only, with the emissions cap

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1 decreasing over time. Phase I of CSAPR took effect on January 1, 2015 and Phase II
2 became effective on January 1, 2017. In 2024, no allowance purchases were required for
3 either the annual or seasonal requirements, and there were no expenses associated with the
4 allowances allocated by the Michigan Department of Environment, Great Lakes, and
5 Energy.

6 **Q. Did Consumers Energy receive revenue credits in 2024 related to the sale of NO_x**
7 **allowances?**

8 A. No. The Company did not sell NO_x emission allowances in 2024. As such, Company
9 witness Leanna E. Feazel's Exhibit A-6 (LEF-1) does not reflect any expense or revenue
10 credits for NO_x emission allowances.

11 **SO₂ Allowance Expenses**

12 **Q. Did Consumers Energy incur expenses or receive revenue credits in 2024 related to**
13 **the SO₂ Allowance Program?**

14 A. Yes. Although the Company did not sell SO₂ emission allowances out of its inventory in
15 2024, it did receive revenue for a portion (\$54) of the Company-allocated SO₂ emission
16 allowances during the annual US Environmental Protection Agency auction.

17 **Q. Are the actual expenses and credits for SO₂ contained in Consumers Energy's 2024**
18 **Reconciliation?**

19 A. Yes. Company witness Feazel includes the actual SO₂ expenses and credits in Exhibit A-6
20 (LEF-1), line 20.

Urea Expenses

Q. What was Consumers Energy's estimate of urea expenses for the 2024 PSCR Plan case?

A. Consumers Energy projected the cost of urea for 2024 to be \$3.7 million as reflected on Exhibit A-18 (NJH-8), line 8, column (b), based on projected generation and SCR operations at the Campbell Complex for Campbell Units 2 and 3.

Q. What were the actual urea expenses?

A. As reflected on Exhibit A-18 (NJH-8), line 8, column (c), actual urea expense for 2024 was \$2.03 million, \$1.67 million lower than projected.

Q. Why were actual urea expenses lower than projected?

A. Urea expenses were lower than forecast due to less consumption and prices being approximately 30% lower than projected. The forecasted value was set conservatively high, based on recent high prices and volatility. The forecasted urea price was \$761/ton, whereas the actual urea cost came in at only \$528/ton.

Aqueous Ammonia

Q. What was Consumers Energy's estimate of aqueous ammonia for the 2024 PSCR Plan case?

A. Consumers Energy projected the cost of aqueous ammonia for 2024 to be \$2.04 million as reflected on Exhibit A-18 (NJH-8), line 8, column (d), based on projected generation and SCR operations at the Covert plant and Zeeland Combined Cycle.

Q. What was the actual aqueous ammonia expense?

A. As reflected on Exhibit A-18 (NJH-8), line 8, column (e), actual aqueous ammonia expense for 2024 was \$1.67 million, \$0.378 million lower than projected.

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1 **Q. Why were actual aqueous ammonia expenses lower than projected?**

2 A. The aqueous ammonia expense for Zeeland was lower than projected due to the actual unit
3 cost landing 35% below the projected unit cost, which was forecasted conservatively high,
4 due to recent price and volatility.

5 The aqueous ammonia expense for Covert was approximately 15% lower than
6 projected because less was required than forecasted. Although Covert's actual quantity
7 was less than forecasted, it aligns with site dispatch/heat rate.

8 **Lime**

9 **Q. What was Consumers Energy's estimate of lime expense in the 2024 PSCR Plan case?**

10 A. Consumers Energy projected the cost of lime for 2024 to be \$8.4 million as reflected on
11 Exhibit A-18 (NJH-8), line 8, column (f), based on projected generation and Spray Dry
12 Absorber ("SDA") and Dry Sorbent Injection ("DSI") operations at the Karn and Campbell
13 plants.

14 **Q. What were the total actual lime expenses?**

15 A. As reflected on Exhibit A-18 (NJH-8), line 8, column (g), the actual lime expense for 2024
16 was \$10.22 million, \$1.81 million higher than projected. The Company consumes hydrated
17 lime at Campbell Units 1 and 2 and consumes pebble lime at Campbell Unit 3. The
18 hydrated lime expense at Campbell Units 1 and 2 was 22%, or \$2.56 million, above
19 forecast.

20 **Q. Why were the actual hydrated lime expenses higher than projected?**

21 A. 2024 hydrated lime expenses were higher than projected for Campbell Units 1 and 2
22 primarily due to the quality of the coal delivered and consumed at Campbell Units 1 and 2.
23 As the units continued to consume the coal that the Company had available, there were

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periods in which the coal was western bituminous, which has significantly higher sulfur content than typical powder river basin, which is what the forecast model is based on.

Q. Please discuss the actual pebble lime expense.

A. 2024 pebble lime expense was 5% or \$0.750 million lower for Campbell Unit 3. In 2024, Campbell Unit 3 operated almost exclusively in “Recycle Mode” vs “Lime Only Mode,” and Lime Only Mode uses significantly more pebble lime than recycle mode.

Activated Carbon

Q. What was Consumers Energy’s estimate of activated carbon for the 2024 PSCR Plan case?

A. Consumers Energy projected the cost of activated carbon for 2024 to be \$2.2 million as reflected on Exhibit A-18 (NJH-8), line 8, column (h), based on projected generation and Activated Carbon Injection operations at Campbell.

Q. What were the actual activated carbon expenses?

A. As reflected on Exhibit A-18 (NJH-8), line 8, column (i), actual activated carbon expenses for 2024 were \$1.981 million, \$0.211 million lower than projected.

Q. Why were activated carbon expenses lower than projected?

A. The 2024 activated carbon expense was lower than projected due to actual dollars/lb coming in about 4% less than forecast. Additionally, it was lower than projected due to the consumption of higher sulfur coal, which generally contains less mercury, and better management of the operating limits for mercury.

2024 Base Load Power Plant Generating Cost Efficiency

Q. Why was Exhibit A-17 (NJH-7) included in this filing?

A. This information was provided in response to the MPSC's Report on Status of Power Quality in Michigan in Case No. U-15945.

Wind Asset Performance Data

Q. Please describe Exhibit A-19 (NJH-9).

A. Exhibit A-19 (NJH-9) presents performance details regarding the Company's owned wind assets. The Commission's September 28, 2023 Order in Case No. U-20803 required this information to be included in future PSCR reconciliation proceedings. Specifically, Exhibit A-19 (NJH-9) includes the 2024 gross actual generation, the 2024 actual and target capacity factor, the 2024 actual and target time-based availability, and the 2024 lost potential MWh due to planned maintenance, repair maintenance, and regulatory curtailment.

Q. Please describe Gross Actual Energy reflected in Exhibit A-19 (NJH-9), column (b).

A. Gross Actual Energy is the gross volume of energy produced by a wind farm during a specific period. The Gross Actual Energy does not represent any adjustment for station power (amount of energy consumed by the wind farm during operations).

Q. Please describe capacity factor reflected in Exhibit A-19 (NJH-9), column (c).

A. Capacity factor is the measure of how often a generation unit operates during a specific period of time. Capacity factor is presented as a percentage and is calculated by dividing the actual unit generation output by the maximum possible generation output. The Company's target capacity factor is presented in Exhibit A-19 (NJH-9), column (d).

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1 **Q. Please describe time-based availability reflected in Exhibit A-19 (NJH-9), column (e).**

2 A. Time-based availability is the measure of the hours when the turbine is available during a
3 specific overall period of time. Time-based availability is presented as a percentage, and
4 97% is generally considered first quartile performance in the industry. Three of the
5 Company's parks outperformed this high standard and one only narrowly missed this
6 performance level. The Company's targeted time-based availability and actual availability
7 is presented in Exhibit A-19 (NJH-9), column (f).

8 **Q. Please describe any significant issues that affected a wind parks ability to meet**
9 **time-based availability targets.**

10 A. Time-based availability targets essentially allow for just one unit to be down before the
11 Company is at risk for not meeting those targets. Gratiot and Crescent wind parks have
12 both experienced issues with blade cracking, as well as a design defect with the blades that
13 have caused significant downtime when the issue presents itself. The blade cracking and
14 design defects have caused units to be shut down to avoid likely catastrophic failures. The
15 units remain down until replacement blades can be procured and installed, which is a costly
16 and timely process.

17 **Q. Please describe potential lost energy for planned and repair maintenance reflected in**
18 **Exhibit A-19 (NJH-9), columns (g) and (h).**

19 A. The potential lost energy for planned and repair maintenance is a calculation of how much
20 energy could have been generated during the periods in which the turbines were out of
21 service. The energy loss is only hypothetical because the calculation assumes sufficient
22 fuel (i.e. wind speed) would have been available for the turbines to operate during the time

1 frame in which they were unavailable for planned and repair maintenance, which in reality
2 would not always be true.

3 **Q. Please describe lost energy for regulatory curtailment reflected in Exhibit A-19**
4 **(NJH-9), column (i).**

5 A. Curtailment reflects the adjustment of the wind turbine blade angles (i.e. parallel to the
6 wind) to slow them down or stop them from turning (also known as “idling”). Wildlife
7 curtailment is implemented when the risk of collision is expected to be high for bird and
8 bat migration through the turbine sweep area, resulting in a reduction in bird and bat
9 collision fatalities. Icing curtailment may also be implemented for local special use permit
10 compliance reasons. The last reason for curtailment is possible implementation for energy
11 market reasons, this typically does not affect the Consumers Energy wind fleet, due to
12 primary dispatch as a “must run” resource.

13 **Q. What is your assessment of the performance of the Company’s wind generation assets**
14 **during 2024?**

15 A. Overall, three out of the five Company wind assets exceeded their targeted time-based
16 availability and, as a result, generated value for customers. Although the actual capacity
17 factors fell short of target capacity factor, the wind generation fleet often exceeding its
18 time-based availability target reflects the fact that the Company maintained its wind
19 generation assets in a condition which would allow for creation of customer value.

20 **Ludington Replacement Power Costs**

21 **Q. Please discuss Exhibit A-20 (NJH-10).**

22 A. Earlier in this testimony, I discussed Ludington outages that were 28 days or greater in
23 length and provided detail on work performed during those periods. While some of those

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1 outages (or portions of those outages) occurred as a result of defective, non-conforming,
2 and incomplete work performed by TAES, some of the outages (or portions of the outages)
3 were also conducted to complete other necessary work, and while down, TAES-related
4 work was performed. If the outage would have occurred regardless of TAES-related
5 defects, then the replacement power costs of the outage are not removed to the regulatory
6 asset approved by the Commission in Case No. U-21310 even if some ancillary
7 TAES-related work was completed. Conversely, Exhibit A-20 (NJH-10) presents only the
8 Ludington outages and associated replacement power costs for work that would not have
9 occurred but for the defective, non-conforming, and incomplete work performed by TAES.
10 The Company has removed replacement power expenses associated with these outages
11 from this reconciliation and has recorded these replacement power costs in the regulatory
12 asset approved by the Commission in Case No. U-21310. Specifically, this order approved
13 the joint application of Consumers Energy and DTE for cost deferral accounting and a
14 regulatory asset for the costs incurred to remediate the defective work performed by TAES.
15 In total, the Company has recorded into the regulatory asset account \$243,441 of
16 replacement power costs incurred in 2024 as a result of defective, non-conforming, and
17 incomplete TAES work. Company witnesses Feazel and Raymond T. Scaife reflect the
18 removal of these replacement power costs in their direct testimony and exhibits.

19 **Q. How did the Company identify Ludington unit outages that occurred as a result of**
20 **defective work performed by TAES?**

21 A. The Company documents outages on the Ludington units and reports the outage
22 information to GADS. To identify whether the outage should be evaluated for replacement
23 power costs, the Company reviews the cause of the outage and the work performed. If the

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1 outage was associated with required inspections and/or repairs of equipment which was
2 subject to issues with TAES' incomplete, non-conforming, and defective work, only the
3 portion of the outage that is attributed to TAES and the associated replacement power costs
4 are removed from this case to the regulatory asset approved by the Commission in Case
5 No. U-21310. More specifically, where an outage was both for normal inspections or
6 maintenance and TAES-related work, in evaluating the cause of the outage and/or the work
7 performed, the Company considers whether the scope of normal planned maintenance
8 activities has increased and resulted in extending normal maintenance outages.

9 **Conclusion**

10 **Q. Please provide a conclusion of your testimony.**

11 A. My testimony described certain outages experienced in 2024 at the Company's
12 fossil-fueled electric generating units and the Ludington Pumped Storage Plant, explained
13 the expense associated with emission allowances for oxides of nitrogen and sulfur dioxide,
14 and explained the expense associated with the consumption of urea, aqueous ammonia,
15 lime, and activated carbon. All generator outages were performed in a reasonable and
16 prudent manner on the part of Consumers Energy. All expenses associated with emissions
17 allowances and consumption of urea, aqueous ammonia, lime, and activated carbon were
18 incurred in a reasonable and prudent manner. Finally, the Company's time-based
19 availability for its wind generation fleet continued to provide value for its customers.

20 **Q. Does this conclude your direct testimony?**

21 A. Yes.

**GENERATION PERFORMANCE STATISTICS
JANUARY 1, 2024 TO DECEMBER 31, 2024**

<u>Line No.</u>	(a)	(b)	(c)	(d)	(e)
	<u>Unit</u>	<u>Unit Availability</u>	<u>MWh Availability</u>	<u>Periodic Factor</u>	<u>Random Outage Rate</u>
1	Campbell 1	81.49%	77.03%	9.55%	14.84%
2	Campbell 2	54.33%	51.93%	0.00%	48.07%
3	Campbell 3 (CE)	83.38%	80.75%	0.00%	19.25%
4	Karn 3	83.01%	74.53%	14.81%	12.51%
5	Karn 4	77.62%	76.32%	16.66%	8.42%
6	Zeeland Simple Cycle	91.96%	91.40%	4.71%	4.08%
7	Zeeland Combined Cycle	84.95%	84.62%	14.38%	1.17%
8	Jackson CC	94.77%	88.61%	5.12%	6.61%
9	Covert CC	80.66%	78.09%	3.79%	18.83%
10	Total Fossil CE ¹	82.89%	78.99%	6.55%	15.47%
11	Base Load Fossil CE	73.07%	73.18%	3.19%	24.41%
12	Ludington 1-6	82.49%	82.50%	10.97%	7.33%
13	Total Hydro	50.75%	47.71%	10.30%	46.81%

¹ Does not include Karn 3 and Karn 4.

Report Period: January 2024 to December 2024

CAMPBELL 1-2 - CAMPBELL 1							
Event	Type	Start	End	Cause	Description	Eq Hrs	Eq MWH
35	U1	2/23/2024 12:24	2/23/2024 12:46	4460	turbine overspeed testing	0.37	95.33
38	U1	2/27/2024 0:01	3/1/2024 0:01	4293	gov valve work	72	18720
39	PO	3/1/2024 0:01	3/31/2024 0:00	4293	gov valve work	718.98	186935.67
41	PE	3/31/2024 0:00	4/5/2024 0:00	4293	gov valve work, continued	120	31200
74	U1	8/25/2024 13:05	9/3/2024 20:07	3499	1C Feeder Issue > 20MW load swings > maxed on FW > FW runback > unit trip	223.03	57988.67
88	U1	10/11/2024 6:29	10/31/2024 17:42	1040	SH tube leak, unit offline	491.22	127716.34
CAMPBELL 1-2 - CAMPBELL 2							
Event	Type	Start	End	Cause	Description	Eq Hrs	Eq MWH
1	U1	1/1/2024 0:00	2/29/2024 0:36	3401	SUBFP failure.	1416.6	396648
2	U1	2/29/2024 8:31	3/1/2024 3:00	3499	Low FW flow when transitioning from SUBFP to MBFP.	18.48	5175.33
3	SF	3/1/2024 3:00	4/10/2024 22:59	4293	Gov valve controller not engaging properly.	978.98	274115.34
16	U1	4/26/2024 13:43	5/7/2024 3:30	4291	Circuit oil cooler leak (water into the oil)	253.78	71059.33
21	U1	5/10/2024 6:59	5/30/2024 5:30	4299	Turbine valve issue, closed unexpectedly and boiler overpressure. Unit trip.	478.52	133984.67
26	U1	6/5/2024 15:54	6/14/2024 4:04	4291	Circuit oil cooler leak (water into the oil)	204.17	57166.67
64	U1	8/21/2024 0:47	8/28/2024 6:29	4302	leak on thrust oil protective trip device.	173.7	48636
73	U1	10/1/2024 20:16	10/11/2024 2:16	1488	FO: 2B SAH issue + L.turb throttle valve steam leak	222	62160
77	U1	11/1/2024 22:54	11/12/2024 23:29	640	U2 FO to address 201A & 210 valves	265.58	74363.34
CAMPBELL 3 - CAMPBELL 3							
Event	Type	Start	End	Cause	Description	Eq Hrs	Eq MWH
43	MO	4/12/2024 13:18	4/27/2024 9:18	1000	Maintenance outage to repair tube leak.	356	302030.41
47	U1	4/27/2024 9:18	6/12/2024 9:04	4410	Turbine Turning Gear failure.	1103.77	934414.98
COVERT GENERATING STATION - COVERT UNIT 1							
Event	Type	Start	End	Cause	Description	Eq Hrs	Eq MWH
6	MO	2/9/2024 7:59	2/12/2024 0:00	3210	Circ Pump Replacement	64.02	25606.67
7	PO	2/12/2024 0:00	2/14/2024 17:29	3210	Circ Pump Replacement	65.48	26193.33
10	U1	3/20/2024 8:30	3/31/2024 19:35	6011	Tube rupture confirmed	275.08	105329.41
11	PO	5/5/2024 0:35	5/11/2024 1:57	3210	Replace 1A Circ Pump	145.37	55660.9
12	U1	5/11/2024 2:19	5/11/2024 4:27	3830	Aux Boiler tripped on low water level, reset and restarted	2.13	816.85
13	U1	5/11/2024 11:48	5/11/2024 15:33	3849	Air line seperated causing low instrument air pressure	3.75	1435.88
17	U1	7/9/2024 20:25	7/13/2024 7:50	9603	Suspected Fuel Gas out of compliance	83.42	30263.56
18	U1	7/23/2024 19:23	7/28/2024 7:26	9623	Removed from service due to high PM Tests	108.05	39200.54
19	U1	7/29/2024 20:23	7/30/2024 12:35	6163	Corrected 1HRS-PV105	16.2	5877.36
33	MO	9/28/2024 0:26	10/7/2024 1:28	4499	Steam Turbine Valve Work	217.03	79716.34
34	U1	10/16/2024 13:04	10/16/2024 16:38	5049	Loss of fuel pressure due to pigging	3.57	1310.04
35	U1	12/12/2024 11:36	12/12/2024 13:08	1799	IP Drum Level Transmitter failed due to being frozen	1.53	613.33
37	PO	12/19/2024 0:27	12/21/2024 2:36	1700	Repair 1FWS-FV131 HP FWR Reg VLV	50.15	20060

INFORMATION FOR UNIT - Campbell Unit 3
PERIODIC OUTAGE

<u>Sequence Number:</u>	Campbell Unit 3-2024-47
<u>Plant/Unit:</u>	Campbell Unit 3
<u>MW Derate:</u>	
<u>Event Year:</u>	2024
<u>Event Number:</u>	47
<u>Start Date:</u>	4/27/2024 9:18
<u>End Date:</u>	6/12/2024 9:04
<u>Outage Type:</u>	U1
<u>Duration (Hours):</u>	1,103.8
<u>MWh Loss:</u>	936,162.6
<u>NERC Cause Code:</u>	4410
<u>NERC Cause Code Description:</u>	Turning gear and motor
<u>Root Cause Description:</u>	Unit unable to operate due to failure of the turbine turning gears
<u>Event Description:</u>	Turbine Turning Gear failure.
<u>Additional Description:</u>	Turning gear failed on startup. Teeth in the planetary gear assembly were found to have sheared off.
<u>Mode of Failure:</u>	Gear failure
<u>Final Corrective Action:</u>	Fabricate and install new replacement gear components
<u>Mechanism Causing:</u>	Preliminary metallurgical examination of the gears were inconclusive due to the level of damage that the gears experienced.
<u>Final Root Cause</u>	Inconclusive, but assumed cyclic fatigue. Turning gear assembly was last inspected in 2016 (with no findings).
<u>Scope to Correct Root Cause:</u>	Fabricate replacement planetary gears and drive shaft to allow for unit operation until the planned retirement in 2025.
<u>Additional Scope:</u>	N/A
<u>If outage Extended for Additional Work & Why:</u>	N/A

**COMPARISON OF CONSUMERS ENERGY AND GADS AVERAGES FOR SIMILAR UNITS
EQUIVALENT AVAILABILITY**

<u>Line No.</u>	(a)	(b)	(c)	(d)	(e)	(f)
		GADS AVERAGES		CONSUMERS ENERGY		CE VERSUS
	<u>UNIT</u>	<u>2017-2023</u>	<u>2023</u>	<u>2020-2024</u>	<u>2024</u>	<u>GADS **</u>
1	Campbell 1	78.47%	76.14%	73.10%	77.03%	Higher
2	Campbell 2	74.74%	73.97%	52.82%	51.93%	Lower
3	Campbell 3	78.41%	78.43%	76.94%	80.75%	Higher

** Higher indicates one-year and/or five-year were higher than the GADs average.
Lower indicates both tests were lower than the GADS average.