BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)) Emergency Order: Midcontinent) Independent System Operator) (MISO)))	Order No. 202-26-22

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

Exhibit 1

May 2025 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

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[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: **<u>FERC Commissioners</u>**
Chairman Mark Christie
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang

<u>Michigan Public Service Commissioners</u>
Chairman Dan Cripps
Commissioner Katherine Peretick
Commissioner Alessandra Carreon

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO))	Order No. 202-26-22

Exhibit to
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Public Interest Organizations

Exhibit 2

Grid Strategies June Report

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

Michael Goggin

June 18, 2025

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

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[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"),

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[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, 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

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[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

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[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

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[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 2023[15] and 2024[16] 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 scenarios[2]**
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 scenarios[4]

Table Notes:
[1]The table provides general criteria. Other factors may influence a higher or lower risk assessment.
[2]**Normal resource scenarios** include planned and typical forced outages as well as outages and derates that are closely correlated to the extreme peak demand.
[3]**Reduced 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.
[4]Even 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.

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[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 year[21] 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]

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[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

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[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 Uri[31] 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.

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[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 monitor[39] and others[40] 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.

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[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. Pfeifenberger 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]

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[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.*

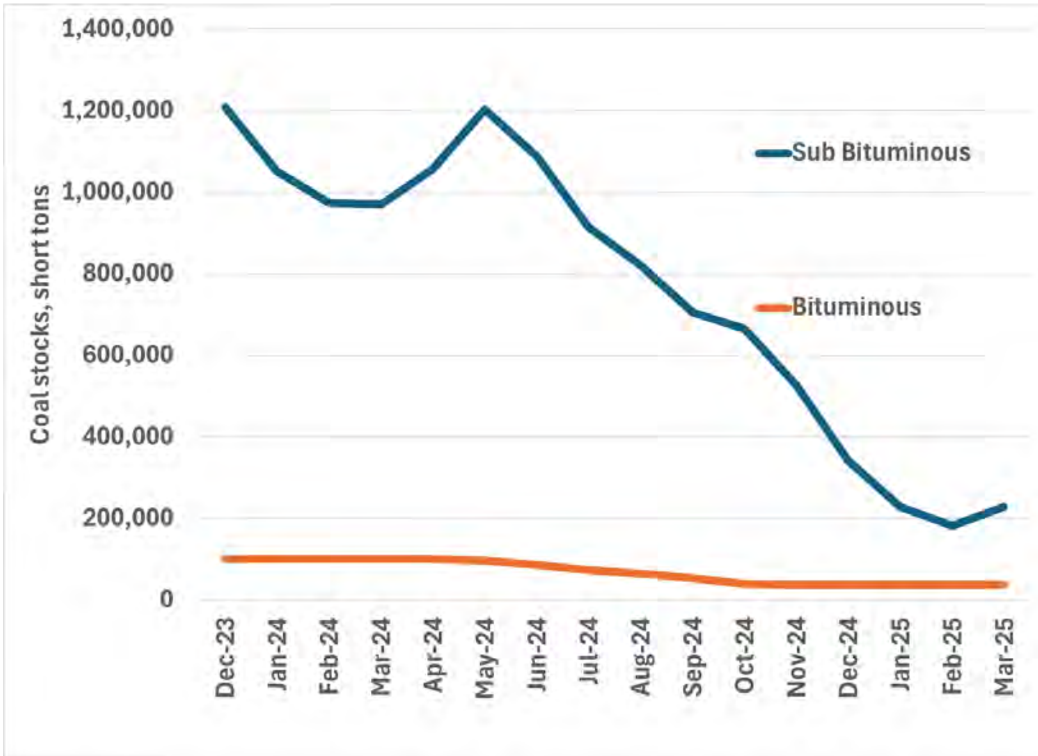

Figure 2: Coal supplies at Campbell, per DOE data

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

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. 202-26-22

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. <u>The extent to which Campbell can operate reliably beginning June 1, 2025</u>

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, respectively[5]—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

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[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 Duration[8]

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

Table 2. Longest 2023 Outages by Type, Units 1-3 - Description and Duration[10]

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

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. CECo dramatically reduced capital and major maintenance spending on Units 1-3 following the IRP that established a May 2025 retirement date. CECo 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 CECo originally proposed in its IRP). Likewise, CECo 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.

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[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 CECo 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] CECo did not carry out most of those projects.

23. Table 5a compares the major maintenance projects CECo proposed carrying out for Units 1 and 2 before deciding to retire those units 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 62 percent across 2022-2025, from a proposed total of \$14.4 million to \$5.5 million. CECo 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 CECo'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 CECo'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 CECo 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. CECo witness Blumenstock states that CECo 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 CECo'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. <u>Whether Campbell can operate effectively as a peaking unit</u>

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]

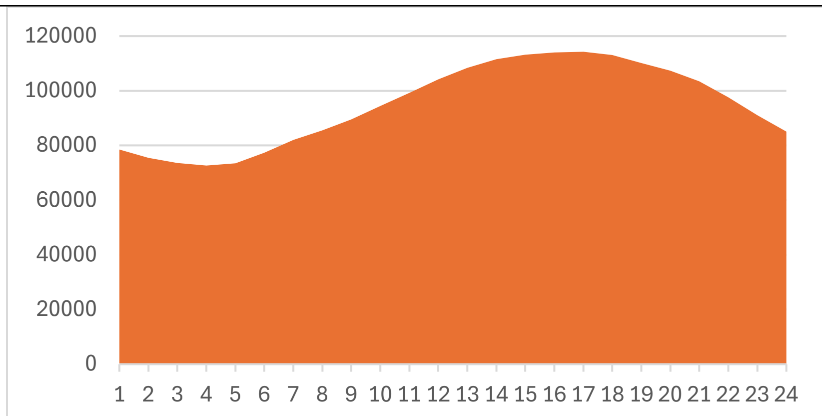
34. Coal units cannot respond to extreme demand events unless they are fully online several hours before the high demand situation occurs. In other words, coal units need

[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 3	• (SCR) catalyst management • Fabric filter bag(s) & cleaning air manifold replacement	1,120,000 3,994,601
2023	1 2 3	• Fabric filter bag replacement • SCR reactor catalyst replacement • Fabric filter bag(s) & cleaning air manifold replacement	1,514,100 2,000,000 3,263,331
2025	3	• SCR reactor catalyst management • Air quality control system (AQCS) equipment repair/replacement	3,000,000 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 SO_2 that occur during operation of Units 1-3, as registered on the continuous opacity, NO_x, or SO_2 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.

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 (NOx) 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 Expert 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 ºF and 13 ºF 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 ºF and 13 ºF. 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 ºF. 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 PM_{10} Emissions at Coal-Fired Plant. Provided expert testimony on whether correlation existed between mass PM_{10} 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 PM_{10} 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, SO_2, 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 SO_2, 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 SO_2 emission control system retrofit schedule. Plant owner argued the installation of advanced NO_x and SO_2 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 SO_2 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 or 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 NOx 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 two 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 installatins 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% O_2) 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, SO_2 and PM Emission Profiles. Performed a comparative evaluation of the NO_x, SO_2 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 rapper 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) PM_{10}/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 $\underline{+}1$ 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-fin air-cooler would eliminate all consumptive water use and wastewater disposal associated with the cooling tower. Air emissions of VOC and PM_{10} 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-fin 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) SO_2 and NO_x refinery heaters and boilers, 2) desulfurization of crude oil, particulate and SO_2 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, H_2S 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. Ratfisch 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 CO_2 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 H_2S 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 O_2), 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 PM_{10} 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. PM_{10} 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 PM_{10} 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 PM_{10} 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 (PM_{10})/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 PM_{10} emissions, though test results indicated that the majority of captured PM_{10} evaporated in the mesh pad and was emitted as VOC.

Aluminum Remelt Furnace/Rolling Mill RACT Evaluations. Lead engineer for comprehensive CO and PM_{10} 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 SO_2, 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 $\pm$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 O_2 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 SO_2 CEMs at Coal-Fired Power Plant. Lead engineer on system audit and challenge gas performance audit of NO_x and SO_2 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 SO_2) 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 SO_2 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 SO_2 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	)	Order No. 202-26-22
Independent System Operator	)	
(MISO)	)	
	)	

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

Exhibit 4

DOE Campbell Memorandum

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 FPA[1] 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.

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[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:**
  - 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. 202-26-22

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

Exhibit 5

DOE Order No. 202-22-4

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 start up. 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 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, NOx, 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. 202-26-22

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 docket[1] 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 Company[2] (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.

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. 202-26-22

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.

Spencer Abraham

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. 202-26-22

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 a have 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. 202-26-22

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 relief.	)	Case No. U-21090

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 7 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 (SO_2), 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. <u>Environmental Law and Policy Center of the Midwest, Ecology Center, Inc., Union of Concerned Scientists, Inc., and Vote Solar</u>

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. <u>Energy Michigan</u>

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 that [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. <u>Consumers</u>

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 <u>exclusion</u> 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)* <u>providing capacity which meets the Local Clearing Requirement of MISO Zone</u> 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 report[2] 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 *Emagine 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. <u>Mackinac Center for Public Policy</u>

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

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[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. <u>Environmental Law and Policy Center of the Midwest, Ecology Center, Inc., Union of Concerned Scientists, Inc., and Vote Solar</u>

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. <u>Hemlock Semiconductor Operations, LLC</u>

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. <u>The Biomass Merchant Plants</u>

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. <u>Wolverine Power Supply Cooperative</u>

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 NOx 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 batter 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' alterative 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. <u>The Biomass Merchant Plants</u>

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. <u>Discussion</u>

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 SO_2, 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 7 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

EXHIBIT A

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

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, Tondu 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 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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CONSUMERS ENERGY COMPANY

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By: Celeste R. Gill Digitally signed by Celeste R. Gill Date: 2022.04.19 15:03:37 -04'00' Date: ____________________

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GREAT LAKES RENEWABLE ENERGY ASSOCIATION

By: Don L. Keskey Date: April 19, 2022

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MICHIGAN ENVIRONMENTAL COUNCIL

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NATURAL RESOURCES DEFENSE COUNCIL

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SIERRA CLUB

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CITIZENS UTILITY BOARD OF MICHIGAN

Digitally signed by Holly L,. Hillyer Date: 2022.04.19 12:29:05 -04'00'

By: ________________________ Date: April 19, 2022

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MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL, INSTITUTE FOR ENERGY INNOVATION, AND CLEAN GRID ALLIANCE

By: Laura A. Chappelle Digitally signed by Laura A. Chappelle Date: 2022.04.19 12:42:00 -04'00' Date: April 19, 2022

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MICHIGAN ELECTRIC TRANSMISSION COMPANY, LLC

By: Richard Aaron Digitally signed by: Richard Aaron DN: CN = Richard Aaron email = raaron@dykema.com C = US O = Dykema Date: 2022.04.19 12:07:55 -04'00' Date: April 19, 2022

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ENVIRONMENTAL LAW & POLICY CENTER, VOTE SOLAR, ECOLOGY CENTER, AND UNION OF CONCERNED SCIENTISTS

By: Margrethe K. Kearney Date: April 19, 2022

Margrethe Kearney, Esq.
Environmental Law & Policy Center
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HEMLOCK SEMICONDUCTOR OPERATIONS LLC

By: Jennifer Utter Heston Digitally signed by Jennifer Utter Heston Date: 2022.04.19 13:15:32 -04'00' ______________________ Date: _April 19, 2022__________

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URBAN CORE COLLECTIVE

By: ______________________ Date: 19-April-2022

Nicholas Leonard, Esq.
Andrew Bashi, Esq.
Great Lakes Environmental Law Center
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Mark N. Templeton, Esq.
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Abrams Environmental Law Clinic
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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'
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MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP

By: John Janiszewski Digitally signed by: John Janiszewski DN: CN = John Janiszewski email = jjaniszewski@dykema.com C = US O = Dykema Gossett, PLLC Date: 2022.04.20 09:49:53 -04'00' ______________________ Date: April 20, 2022

John A. Janiszewski, Esq.
Dykema Gossett PLLC
201 Townsend Street, Suite 900
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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**

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-22

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   Case No. U-21389
for authority to increase its rates
for the generation and distribution   Volume 4
of electricity and for other relief.

____________________________________/

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)

S T A T E O F M I C H I G A N

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

May 2023

Q. Please state your name and business address.

A. My name is Richard T. Blumenstock, and my business address is 1945 West Parnall Road, Jackson, Michigan, 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your position with Consumers Energy?

A. I am currently the Executive Director of Electric Supply Engineering. I began employment at the Company in May 1994 in the electric transmission planning area where I performed planning studies on the Company's distribution and transmission systems. In April 2002, I was assigned to the electric operations area where I oversaw engineering operations for the distribution and transmission systems. In August 2009, I was assigned to the fuel supply area where I oversaw the Company's purchasing and transport functions for fuel for electric generation. In June 2011, I assumed additional responsibilities including oversight of the Company's interaction in the Midcontinent Independent System Operator, Inc. ("MISO") markets; wholesale settlements and transactions functions; Power Supply Cost Recovery ("PSCR") activities; and planning for electric supply necessary to satisfy customers' energy and capacity needs. In September 2019, I assumed the role of Executive Director of Electric Planning, overseeing the company-wide efforts for all electric planning. In September 2022, I assumed my current position as Executive Director of Electric Supply Engineering.

Q. What are your responsibilities as Executive Director of Electric Supply Engineering?

A. My responsibilities as Executive Director of Electric Supply Engineering include oversight of all activities associated with planning and design for the Company's electric generation portfolio.

Q. What is your formal educational experience?

A. I received a Bachelor of Science degree in 1992 and a Master of Science degree in 1994, both in Electrical Engineering from Michigan Technological University.

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-16045-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2010;
- Case No. U-16432-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2011;
- Case No. U-16890: Approval of a PSCR Plan and for Authorization of Monthly PSCR Factors for the Year 2012;
- Case No. U-16890-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2012;
- Case No. U-17429: Approval of a Certificate of Necessity for the Thetford Generating Plant pursuant to MCL 460.6s and for related accounting and ratemaking authorizations;
- Case No. U-17317: Approval of a PSCR Plan and for Authorization of Monthly PSCR Factors for the Year 2014;
- Case No. U-17317-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2014;
- Case No. U-17752: Authority to amend its renewable energy plan approved in Case Nos. U-15805, U-16543, U-16581, and U-17301;
- Case No. U-17678: Approval of a PSCR Plan and for Authorization of Monthly PSCR Factors for the Year 2015;

- 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;

- 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

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 its generating asset projected performance metrics. 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.

SECTION I

GENERATION ASSETS

Q. Please provide an overview of the Company's generation assets.

A. As of December 21, 2022, the Company's total projected owned generation assets for the 2023/2024 Planning Year had a Generator Verification Test Capacity ("GVTC") of 6,647 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	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)

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 784 MW capacity reported is 93% of the Campbell Unit 3 GVTC, reflecting the Company's share of ownership.

Q. What does "owned share" mean when used with respect to Ludington Pumped Storage Plant ("LPS" or "Ludington") Units 1 through 6?

A. The Company owns 51% of LPS and DTE Electric Company ("DTE") owns the remaining 49%. Thus, the 1,160 MW capacity reported is 51% of the total LPS GVTC, reflecting the Company's share of ownership.

Q. Do any of the Company's owned generation units reflect retirement dates which are different from those sponsored in the Company's previous electric rate case, Case No. U-21224?

A. Yes. The retirement dates for Karn Units 3 and 4 reflect different retirement dates. The Company filed its 2021 IRP in Case No. U-21090 on June 30, 2021 and in its Proposed Course of Action ("PCA"), the Company proposed the retirement of Karn Units 3 and 4 by May 31, 2023, coincident with the retirement of Karn Units 1 and 2. However, the Settlement Agreement reached in the 2021 IRP reflected continued operation of Karn Units 3 and 4 through May 31, 2031. In addition, the Covert Plant was not reflected in the Company's owned generating units in Case No. U-21224 but will be included in the Company's generating resources effective June 1, 2023, as will be discussed in more detail later in this direct testimony. Finally, Karn Units 1 and 2 have been removed due to their pending retirement.

Q. How will the Company continue to meet its load requirements with the retirement of the Campbell units in 2025?

A. The Settlement Agreement approved in the Company's 2021 IRP reflects the replacement of the Campbell unit capacity through a number of different resources including continued growth of its solar generation assets, demand response, energy waste reduction, the acquisition of the Covert Plant by June 1, 2023, continued operation of Karn Units 3 and 4, and the addition of 700 Zonal Resource Credits ("ZRCs") by June 1, 2025, through a one-time solicitation approved as part of the Settlement Agreement.

The Covert Plant is a 1,089 MW natural gas-fired combined cycle generating unit in Van Buren County. The addition of Covert, 700 ZRCs through a one-time solicitation, continued operation of Karn Units 3 and 4, along with Consumers Energy's current natural gas-fired power plants in Zeeland and Jackson — will meet Michigan's energy needs when renewables and other sources are not available.

<u>GENERATION ASSET STRATEGY</u>

Q. Please describe the Company's asset strategy for its generating units.

A. The Company's generation asset strategy is focused on providing safe, reliable, regulatory compliant, and economic energy and capacity for its customers. This strategy will be implemented within the construct of the Company's clean energy goals and its IRPs, 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 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. A detailed discussion of River Hydro compliance is discussed in the direct testimony of Company witness Monroe.

Consistent with the approval of the Company's PCA in its 2021 IRP, the Company will concentrate investment on the gas-fired units as they will provide the greatest long-term customer benefit. The coal-fired units will have less investment as they approach retirement. During 2022, the Company's Zeeland and Jackson Plants produced over 27% of the energy value and over 25% of the capacity value realized by the Consumers Energy generating fleet (excluding renewables). The addition of the Covert Plant on June 1, 2023 will significantly increase the energy and capacity value for the Company's gas-fired generation. As such, the Company's investment focus and associated performance projections, have been correspondingly set for these generating units.

Q. How does the Company's generation asset strategy apply to the balance of the Company's generating units?

A. The Company's generation asset strategy with respect to the remaining generating units will vary depending on each unit's energy value, capacity value and, consistent with the Company's currently approved IRP expected retirement dates. The Company will continue to maintain its generating units, including the River Hydros, to ensure safe and environmentally compliant operations. With the exception of the River Hydros, I will provide additional detail regarding the Company's generation asset strategy for each of the generating units, or group of generating units, in the portion of this direct testimony 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.

Q. What factors cause an increase or decrease in ROR?

A. The frequency and/or duration of a forced or unplanned generating unit outage or generating unit de-rate directly affects ROR. Reducing the frequency and/or duration of forced or unplanned generating unit outages and generating unit de-rates decreases ROR. Conversely, increasing the frequency and/or duration of forced or unplanned generating unit outages and generating unit de-rates degrades ROR.

Q. How are ROR projections for the Generating units developed?

A. The ROR projections for the projected test year ending February 28, 2025 were developed from the five-year (2018-2022) average. These five-year averages were then adjusted to reflect current operating conditions and projected unit investment. The projected unit investment is developed in accordance with the Company's generation asset strategy. These five-year historical ROR average values are presented in Exhibit A-40 (RTB-2), column (b).

Q. Please define PF.

A. PF is a measure of the percent of lost availability that results from planned outages, planned outage extensions, planned de-rates, and planned de-rate extensions. Planned derates can be taken for a variety of reasons, including the performance of necessary maintenance work which does not require an outage to perform, or the combustion of a coal blend with a lower heat content than is required to achieve the net demonstrated capability of the unit.

Q. What strategy does the Company employ to minimize the impact of planned outages on its customers?

A. Consistent with the Company's generation asset strategy, the Company endeavors to schedule planned generating unit outages during periods in which the margin between the generating unit production cost and the projected MISO energy market price is lowest. This strategy results in creating greater NEV as I will discuss in more detail later in this direct testimony. In general, the projected MISO energy market pricing is lower in the shoulder months of spring and fall due to historically lower demand. However, with the introduction of seasonal capacity in the MISO market, the Company will also consider the impact of outage scheduling on capacity accreditation for the four capacity seasons. Company witness Metz describes seasonal capacity in more detail in her testimony.

Q. Does this outage scheduling strategy apply to all of the Company's generating units?

A. No. For those generating units which have higher production costs and, as a result, are less likely to be dispatched, the available window for scheduling generating unit outages is much larger. The specific strategy for each generating unit or category of generating units will be discussed in more detail later in this testimony.

Q. Please define Projected Availability.

A. Projected Availability is a measure of the percent of time that a generating unit or category of generating units is projected to be available to generate electricity.

Q. How is Projected Availability determined for each generating unit or category of generating units?

A. The Projected Availability for each generating unit or category of generating unit is a simple combination of the PF and the projected ROR. Projected Availability is the key performance metric for implementation of the Company's generation asset strategy for each generating unit or category of generating unit.

Q. How does the Company's generation asset strategy inform Projected Availability?

A. As I previously discussed, our generation asset strategy and associated generation investment will focus on each unit's ability to provide economic value to customers through the unit's ability to produce energy and capacity value in the respective MISO markets. As such, those generating units or category of generating unit providing the greatest amount of economic value to customers will be targeted to achieve the highest projected availabilities.

Q. How can the Company impact Projected Availability for a generating unit?

A. The Company can directly impact Projected Availability for a generating unit by minimizing both PF and ROR for that unit. With respect to minimizing PF, the Company can employ incremental resources during a planned outage to ensure that the critical path for the outage is as short as possible. This strategy could include working 24-hours, seven days a week, for the duration of the outage. Similarly, when a unit experiences an unplanned outage, the Company can employ necessary resources to ensure the unit is returned to available status as quickly as practical. In addition to minimizing unforced outage length, the Company could invest in a generating unit to increase its reliability and, as a result, decrease the generating unit's projected ROR.

Q. Does the Company attempt to maximize availability for all its generating units or category of generating units?

A. No. Consistent with the Company's generation asset strategy, the Company focuses on sustaining availability for those generating units which provide the greatest economic benefit to customers through the energy value provided. The Company's generating units get dispatched by MISO as part of the MISO energy market. Based upon the Company's projected dispatch likelihood for each unit, the Company will rank the generating units from highest economic value to least economic value, and manage the PF and the ROR, and therefore the unit's Availability, to allow for the highest customer value. Or, stated differently, the PF and ROR values may be allowed to be higher (lower unit Availability) for the lower economic value units, and will be managed to lower values (higher unit Availability) for higher economic value units.

Q. How does the Availability projection reflect the customer benefit?

A. An improvement in Availability can translate to a customer benefit in several ways. The immediate benefit is that the generating unit or the category of generating unit is available for dispatch for a greater number of hours throughout the year, likely leading to increased generation, and consequently higher NEV, on an annual basis. Additionally, higher availability increases the ZRCs, increasing the capacity value of the unit.

Q. How does the Company measure the customer benefit resulting from increased generation?

A. The Company utilizes NEV to quantify this customer benefit. At a high level, NEV of a generating unit is the difference between the market value of energy and the cost of producing and supplying that energy. NEV is the net customer benefit of a generator's energy production expressed in dollars. These values are presented in Exhibit A-40 (RTB-2), column (f), which identifies five-year (2018-2022) actual NEV amounts.

Q. What can the Company do to positively affect NEV?

A. Typically, economic investments that improve the reliability and availability of the generating unit or category of unit will result in increasing NEV. Economic investments that result in a reduction in the cost to generate will also result in increasing NEV, all else being equal. Positive NEV increases when a generating unit operates more frequently during periods in which market pricing exceeds the cost of production for that unit. Historically, market pricing has tended to be higher in the summer and winter, although there is variability to market conditions. As discussed earlier in my testimony, this is the reason that periodic outages are generally scheduled in the shoulder months of spring and fall. Market prices are typically lower during this time period, thereby reducing the PSCR impact of each scheduled outage.

Q. Does the cost of production vary for the Company's generating units?

A. Yes. The basis for the Company's generation asset strategy is directly related to this actuality. The Company's investment strategy is focused on those units with the lowest variable production costs to maximize NEV for our customers. As the Company strategically invests additional funds in a generating unit to increase its reliability, the expectation is for the generating unit's reliability to be higher than otherwise possible absent the investment. Higher reliability, in turn, increases the likelihood the unit is available during periods when market prices exceed the production cost of the unit, thus increasing the NEV of the unit.

Q. Why is the measurement of NEV important to the Company and its customers?

A. Positive NEV reflects a direct and immediate reduction to customer power supply costs and consideration of NEV provides a basis for making operational and financial decisions in order to maximize the customer value of the generating unit.

Q. What is another measure the Company uses to evaluate economic projects for its generating units?

A. In addition to measuring NEV for a generating unit, the Company also considers the impact a higher availability (specifically ROR) will have on the amount of capacity available from a particular generating unit which receives a monetary credit in the MISO Resource Adequacy Market. Table 2 below summarizes the capacity value of the Company's generating units in the 2022-2023 PRA for Zone 7. Company witness Metz discusses the capacity value of the Company's generating units in 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]
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.

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 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. Projects that are targeted to improve reliability will not be considered.

Q. How will the Company's generation asset strategy for Campbell Units 1 and 2 impact their projected performance?

A. It is anticipated that the unit performance will degrade from current performance for both Campbell Units 1 and 2, and this risk will be accepted to limit new investment as the units near retirement. Based upon the Campbell Units 1 and 2 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 16.00% at Campbell Unit 1 and 14.50% at Campbell Unit 2 in the test year, as shown on Exhibit A-40 (RTB-2), lines 1 and 2, column (c). During the five-year historical period from 2018 through 2022, Campbell Unit 1 had an ROR of 15.56% and Campbell Unit 2 had an ROR of 17.33% as shown on Exhibit A-40 (RTB-2), lines 1 and 2, column (b).

Q. How is this strategy reflected in the Projected Availability for Campbell Units 1 and 2 in the test year?

A. The Projected Availabilities for Campbell Units 1 and 2 in the test year are 78.23% and 70.12%, respectively, as shown on Exhibit A-40 (RTB-2), lines 1 and 2, column (e). The Projected Availability for Campbell Unit 1 reflects a projected ROR of 16.00% and a PF of 6.87%, as shown on Exhibit A-40 (RTB-2), line 1, columns (c) and (d). The planned Campbell Unit 1 outage for the test year is scheduled to begin on October 11, 2024 and last for 25 days. Projected Availability for Campbell Unit 2 reflects a projected ROR of 14.50% and a PF of 17.99%, as shown on Exhibit A-40 (RTB-2), line 2, columns (c) and (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.

Q. How will the Company's generation asset strategy for Campbell Unit 3 impact its projected performance?

A. It is anticipated that unit performance will remain relatively consistent with current performance. Based upon the Campbell Unit 3 capital and major maintenance projects 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-40 (RTB-2), line 3, column (c). During the five-year historical period from 2018 through 2022, Campbell Unit 3 had an actual ROR of 11.70%, as shown on Exhibit A-40 (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 84.44%, as shown on Exhibit A-40 (RTB-2), line 3, column (e). This Availability for Campbell Unit 3 reflects a projected ROR of 8.00% and a PF of 8.22%, as shown on Exhibit A-40 (RTB-2), line 3, columns (c) and (d). The planned outage for the test year is scheduled to begin on April 16, 2024 and last for 30 days, as reflected on Exhibit A-39 (RTB-1), line 4. The outage is scheduled during a period in which energy prices are projected to be lower, thereby reducing the impact of the outage on customers.

Q. How does the Campbell Unit 3 Availability translate into customer value?

A. As reflected on Exhibit A-40 (RTB-2), line 3, column (f), during the five-year historical period from 2018 through 2022, Campbell Unit 3 had an NEV of $365.3 million. The 2022 NEV for Campbell Unit 3 was $190.2 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 2022-2023 PRA is $57.3 million and the Campbell Unit 3 hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2022-2023 PRA is $43.0 million.

Q. Please provide an overview of the generation asset strategy for Karn Units 1 and 2.

A. The strategic plan for Karn Units 1 and 2 is predicated on their planned retirement on May 31, 2023 as documented in the Company's approved Settlement Agreement in the Company's 2018 IRP, Case No. U-20165. The overall remaining life objective for Karn Units 1 and 2 is to maintain economic dispatch from the customer's perspective. Economic O&M expenses through retirement on May 31, 2023, are targeted to maintain operable, safe, and regulatory compliant units through their retirement date. No capital expenditures are included in the plan.

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 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. Projects that are targeted to improve reliability will not be considered.

Q. How will the Company's generation asset strategy for Karn Units 3 and 4 impact their projected performance?

A. It is anticipated that unit performance for Karn Units 3 and 4 will slightly degrade from current performance. Based upon the Karn Units 3 and 4 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 16.50% at Karn Unit 3 and 17.50% at Karn Unit 4 in the test year, as shown on Exhibit A-40 (RTB-2), lines 4 and 5, column (c). During the five-year historical period from 2018 through 2022, Karn Unit 3 had an ROR of 36.05% and Karn Unit 4 had an ROR of 29.51%, as shown on Exhibit A-40 (RTB-2), lines 4 and 5, column (b).

Q. How is this strategy reflected in the Projected Availability for Karn Units 3 and 4 in the test year?

A. The projected availabilities for Karn Units 3 and 4 in the test year are 61.02% and 73.90%, respectively, as shown on Exhibit A-40 (RTB-2), lines 4 and 5, column (e). The availability for Karn Unit 3 reflects a projected ROR of 16.50% and a PF of 26.92%, as shown on Exhibit A-40 (RTB-2), line 4, columns (c) and (d). The planned outage for the test year is scheduled to begin on March 1, 2024 and last for 43 days, as reflected on Exhibit A-39 (RTB-1), line 1. The availability for Karn Unit 4 reflects a projected ROR of 17.50% and a PF of 10.43%, as shown on Exhibit A-40 (RTB-2), line 5, columns (c) and (d). The planned outage for the test year is scheduled to begin on March 31, 2024 and last for 38 days, as reflected on Exhibit A-39 (RTB-1), line 2.

Q. How does the Projected Availability for Karn Units 3 and 4 translate into customer value?

A. As reflected on Exhibit A-40 (RTB-2), lines 4 and 5, column (f), during the five-year historical period from 2018 through 2022, Karn Unit 3 had a NEV of -$8.1 million and Karn Unit 4 had a NEV of -$11.1 million. The 2022 NEV for each of these units was -$0.9 million and -$4.1 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 for several reasons, including the need to perform unit demonstration testing, unit performance, and conduct operator training. Due to the production cost for the units, the units get dispatched far less than the Company's other generating assets. 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 value in the form of relatively cheap capacity, 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 2022-2023 PRA is $17.9 million for Karn Unit 3 and $34.1 million for Karn Unit 4. The hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2022-2023 PRA is $13.4 million for Karn Unit 3 and $25.6 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 maintain economic dispatch and capacity from the customer's perspective. The units provide significant value to customers in both the energy and resource adequacy markets. 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 reliability will be included in the plan if 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-40 (RTB-2), lines 13 through 15, column (c). During the five-year historical period from 2018 through 2022, the Zeeland Plant had ROR values at or below 4.77% for all units, as shown on Exhibit A-40 (RTB-2), lines 13 through 15, column (b).

Q. How is this strategy reflected in the Projected Availability for the Zeeland Plant in the test year?

A. The Projected Availability for the combined cycle generating units (Units 1 and 2) at the Zeeland Plant in the test year is 90.79%, as shown on Exhibit A-40 (RTB-2), line 13, column (e). The Zeeland combined cycle (Units 3, 4, and 5) generating unit availability is based upon a projected ROR of 4.0% and a PF of 5.43%, as shown on Exhibit A-40 (RTB-2), line 13, columns (c) and (d). The Projected Availabilities for the simple cycle generating units at the Zeeland site in the projected test year are 93.73% and 92.75%, respectively, as shown on Exhibit A-40 (RTB-2), lines 14 and 15, column (e). The Zeeland simple cycle generating unit Projected Availabilities are based upon projected RORs of 4.0% and PFs of 2.36% and 3.39%, respectively, as shown on Exhibit A-40 (RTB-2), lines 14 and 15, columns (c) and (d). There are no outages greater than 28 days scheduled for the Zeeland combined cycle units (Units 3, 4, and 5) in the projected test year ending February 28, 2025, however there are several shorter duration outages of 10 days each scheduled in May and October. There are also no outages greater than 28 days scheduled for the Zeeland simple cycle units (Units 1 and 2) however several shorter planned outages are scheduled for those units in April and May 2024, lasting a total of nine days for Unit 1 and 13 days for Unit 2. 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 Zeeland Plant Projected Availability translate into customer value?

A. As reflected on Exhibit A-40 (RTB-2), lines 13 through 15, column (f), during the five-year historical period from 2018 through 2022, the Zeeland Plant provided a total NEV of $197.3 million. The 2022 NEV for Zeeland was $89.0 million.

Q. Please quantify the capacity value for the Zeeland Plant.

A. As reflected in Table 2, the Zeeland Plant capacity value based upon the settlement price for Zone 7 in the 2022-2023 PRA is $74.1 million and the Zeeland Plant hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2022-2023 PRA is $55.6 million.

Q. Please provide an overview of the generation asset strategy for the Jackson Plant.

A. The strategic plan for the Jackson Plant is predicated on plant operation through Planning Year 2040. The overall long-term objective for the Jackson Plant is to maintain economic dispatch and capacity from the customer's perspective. The units provide significant value to customers in both the energy and resource adequacy markets. 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 reliability will be included in the plan if they provide value to customers.

Q. How will the Company's generation asset strategy for the Jackson Plant impact its projected performance?

A. It is anticipated that site performance will remain relatively consistent with current performance. Based upon the Jackson Plant 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 4.50% at the Jackson Plant in the test year, as shown on Exhibit A-40 (RTB-2), line 16, column (c). During the five-year historical period from 2018 through 2022, the Jackson Plant had an actual ROR of 6.38%, as shown on Exhibit A-40 (RTB-2), line 16, column (b).

Q. How is this strategy reflected in the Projected Availability for the Jackson Plant in the test year?

A. The Projected Availability for all of the generating units at the Jackson site in the test year is 91.25%, as shown on Exhibit A-40 (RTB-2), line 16, column (e). The Projected Availability for the Jackson site reflects a projected ROR of 4.50% and a PF of 4.45%, as shown on Exhibit A-40 (RTB-2), line 16, columns (c) and (d). There are no major planned outages in excess of 28 days for the Jackson units in the test year, however a short 12-day outage is scheduled to begin September 29, 2024. In addition, several derates are scheduled to perform inspections and maintenance on various generating units in April and September 2024.

Q. How does the Jackson Plant Projected Availability translate into customer value?

A. As reflected on Exhibit A-40 (RTB-2), line 16, column (f), during the five-year historical period from 2018 through 2022, the Jackson units provided a total NEV of $152.0 million. The 2022 NEV for the Jackson Plant was $74.2 million.

Q. Please quantify the capacity value for the Jackson Plant.

A. As reflected in Table 2, the Jackson Plant capacity value based upon the settlement price for Zone 7 in the 2022-2023 PRA is $46.6 million and the Jackson Plant hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2022-2023 PRA is $35.0 million.

Q. How will the Company's generation asset strategy for the Covert Plant impact its projected performance?

A. It is anticipated that site performance will remain relatively consistent with past performance under different ownership. Based upon the Covert Plant 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 0.96% to 1.74% at the Covert Plant in the test year, as shown on Exhibit A-40 (RTB 2), lines 17 through 19, column (c).

Q. How is this strategy reflected in the Projected Availability for the Covert Plant in the test year?

A. The Projected Availability for each of the combined cycle generating units at the Covert Plant in the test year ranges from 93.07% to 93.81%, as shown on Exhibit A-40 (RTB-2), lines 17 through 19, column (e). The Covert combined cycle generating unit availability is based upon projected ROR of 0.96% to 1.74% and a PF of 5.28%, as shown on Exhibit A-40 (RTB-2), lines 17 through 19, columns (c) and (d). There are no outages greater than 28 days scheduled for the Covert Plant combined cycle units (Units 1, 2, and 3) in the projected test year ending February 28, 2025, however there is a shorter duration outage of 19 days scheduled for each unit. These outages are scheduled for October and November 2024, periods in which energy prices are projected to be lower, thereby reducing the impact of the outages on customers.

Q. How will the Covert Plant Projected Availability translate into customer value?

A. The Company projects that the Covert Plant combined cycle units will provide NEV that is approximately twice that of the Jackson and Zeeland Combined Cycle Units.

Q. Please quantify the capacity value for the Covert Plant.

A. As reflected in Table 2, the Covert Plant capacity value based upon the settlement price for Zone 7 in the 2022-2023 PRA is $91.4 million and the Covert Plant hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2022-2023 PRA is $68.6 million.

Q. Please provide an overview of the generation asset strategy for the River Hydro units.

A. A full discussion of the Company's River Hydro generation asset strategy is included in the direct testimony of Company witness Monroe.

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 Company has recently completed a major overhaul of the Ludington units which is intended to provide increased capacity and generation, increased efficiency, and an extended service life which directly supported the 50-year Federal Energy Regulatory Commission ("FERC") license extension. The value for these units resides primarily in the resource adequacy market (capacity market) with the ability to generate power rather instantaneously when electric energy prices are high, or pump power rather instantaneously when electric energy prices are low. The overall long-term objective for Ludington is to maintain reliable reserve capacity for customers. The capital expenditures and major maintenance expenses in the plan are targeted to increase unit capacity and efficiency and 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 be considered if they provide significant value to customers. Ludington is also 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 discussed in Mr. Monroe's direct testimony.

Q. How will the Company's generation asset strategy for Ludington impact its projected performance?

A. It is anticipated that Ludington performance will remain relatively consistent with current performance through the projected test year. Based upon the Ludington capital and major maintenance projects that I will discuss later in this direct testimony, as well as the Ludington unit major overhauls performed over the past eight years, the Company's generation asset strategy is expected to result in an ROR of 4.00% for the Ludington units in the test year, as shown on Exhibit A-40 (RTB-2), lines 6 through 11, column (c). During the five-year historical period from 2018 through 2022, the Ludington units had average ROR values ranging from 1.70% to 9.30%, as shown on Exhibit A-40 (RTB-2), lines 6 through 11, column (b).

Q. How do the Ludington Pumped Storage Units factor into the Company's future renewable energy strategy as outlined in the IRP?

A. Given the intermittent nature of solar and wind generation and the Company's plans to move to a zero net carbon future, Ludington is becoming a more critical component of the Company's generation portfolio. Ludington can deliver a significant amount of energy in a short time period; providing energy supply from the reservoir during periods when the wind doesn't blow and/or the sun doesn't shine. Additionally, when there is an over-abundance of wind and/or solar generation, Ludington can utilize the excess energy to fill the reservoir. Ludington's large energy storage capability greatly enables the transition to renewable energy.

Q. How is this strategy reflected in the Projected Availability for Ludington in the test year?

A. The Projected Availabilities for all of the Ludington units in the projected test year ranges from 79.52% to 87.44%, as shown on Exhibit A-40 (RTB-2), lines 6 through 11, column (e). The Projected Availabilities for the Ludington generating units reflect a projected ROR of 4.00% and PFs ranging from 8.92% to 17.17%, as shown on Exhibit A-40 (RTB-2), lines 6 through 11, columns (c) and (d). There are two major outages planned for the Ludington units that will begin in the test year; Ludington Units 3 and 4 each have an outage scheduled to begin on February 10, 2025 and last 120 days, as reflected on Exhibit A-39 (RTB-1), lines 6 and 7. In addition, shorter outages on all six Ludington units are scheduled throughout the test period. The outages are scheduled during periods in which the likelihood of Ludington unit dispatch is lower, thereby reducing the impact of the outages on customers.

Q. How does the Ludington Unit Projected Availability translate into customer value?

A. As reflected on Exhibit A-40 (RTB-2), lines 6 through 11, column (f), during the five-year historical period from 2018 through 2022, the Ludington units provided a total NEV of $32.8 million. The 2022 NEV for Ludington was $23.8 million.

Q. Please quantify the capacity value for Ludington.

A. As reflected in Table 2, the Ludington capacity value based upon the settlement price for Zone 7 in the 2022-2023 PRA is $96.5 million and the Ludington hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2022-2023 PRA is $72.4 million.

Q. Please provide an overview of the generation asset strategy for the Renewable Energy Assets.

A. The Company's strategic plan for Renewable Energy Assets, both wind and solar, is entirely driven by the Company's MPSC-approved 2021 IRP Settlement Agreement. Consistent with the IRP, the strategy for the wind assets is to complete construction and have all wind assets in service in 2024 with the completion of Heartland Wind Farm. With respect to solar, the Company plans to continue to add incremental solar resources in accordance with its Clean Energy Plan and Renewable Energy Plan. These solar resources are being added pursuant to the Company's 2018 IRP and 2021 IRP annual solicitations, as discussed in more detail later in this direct testimony. In addition, the Company anticipates that it will also add up to 1,000 MW of wind and solar assets through 2027[1] in support of the Company's voluntary green pricing program and their costs will be reconciled through the Company's renewable energy plan. The overall investment objective for the Company-owned assets is to provide funding for projects as appropriate to maintain economic dispatch and capacity from the customer's perspective. The Company has an energy-based availability target of 91% for its renewable energy wind assets. This availability target considers those periods during which the wind is sufficient to produce energy. The capital expenditures and major maintenance expenses in the plan are targeted to maintain the designed performance level.

Q. How do the Company's renewable assets translate into customer value?

A. Similar to the Company's 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. As reflected on Exhibit A-40 (RTB-2), lines 20 through 21, column (f), during the four-year historical period from 2019 through 2022, the Cross Winds Energy Park and the Lake Winds Energy Park provided a total NEV of $141.1 million. The 2022 NEVs for Cross Winds Energy Park and Lake Winds Energy Park were $43.1 million and $15.4 million, respectively. As reflected on Exhibit A-40 (RTB-2), lines 22 through 23, column (f), the 2022 NEVs for Gratiot Farms Wind and Crescent Wind were $24.7 million and $23.4 million, respectively. The Company began to measure the NEV for its solar assets in 2020 and the 2020 through 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.

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 2022-2023 PRA is $5.7 million and the renewable asset hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2022-2023 PRA is $4.3 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 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.

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

control equipment and/or a combination of the two. The Company will continue to monitor the progress of the proposed rule and evaluate the various options for compliance with the rule.

Q. What are the capital investments and/or O&M expenses the Company is seeking recovery of in this case that are specifically related to air quality control?

A. Any capital and/or O&M required for the operation of the air quality control systems that the Company is seeking recovery can be found in Exhibit A-12 (RTB-3), Schedule B-5.1.

Q. Are you seeking recovery of any expenses related to the regulation of greenhouse gases from EGUs?

A. No, not at this time. On June 19, 2019, the EPA finalized three rulemakings related to the regulation of greenhouse gases, specifically carbon dioxide, from EGUs: (i) repeal of the Clean Power Plan; (ii) issuance of the final Affordable Clean Energy (“ACE”) Rule and; (iii) issuance of new Clean Air Act (“CAA”) Section 111(d) regulations. This rule was subsequently overturned in litigation, and the EPA issued the final Good Neighbor Plan on March 15, 2023. The Good Neighbor Plan requires reductions in oxides of nitrogen emissions from power plants and industrial facilities for 23 states, including Michigan. The Company is in the process of evaluating the impacts of the Good Neighbor Plan on its fossil generating units.

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. This bill provides authority for state implementation of coal ash management through a state permit program in lieu of the current enforcement of the CCR Rule through the RCRA Citizen Suit Authority. States may elect to submit a CCR permit program to the EPA for approval. The State of Michigan revised its solid waste statute in late 2018 to outline a state CCR permitting program. Michigan has submitted its application to the EPA for a permit program and is awaiting the EPAs review of administrative completeness. In the interim, the EPA has enforcement authority over the RCRA-CCR Rule as provided in the WIIN Act.

The existence of a state permitting program allows Department of Environment, Great Lakes, and Energy ("EGLE") to issue permits under Michigan's solid waste management statute (Part 115 of the Natural Resources and Protection Act of 1994 ("NREPA"), as amended) to regulate compliance schedules and activities for CCR landfills and surface impoundments. Although the current state CCR permitting program was passed into law and Consumers Energy is obligated to comply with the associated statute, permits, and licenses, the program must be approved by the EPA on the basis that it is "as protective as" the CCR Rule to avoid dual state and federal regulation. Thus, similar compliance standards are required within the state permitting program, including requirements to make compliance documentation publicly available, completing the work, and then self-reporting by providing notifications to EGLE and posting to a publicly accessible compliance website.

Q. What are the capital and/or O&M investments Consumers Energy is seeking recovery of in this case that are specifically related to RCRA compliance and/or overall CCR Management?

A. The Company's CCR management compliance strategy was approved in Case No. U-18322. The major capital work for compliance has been completed. The capital and/or O&M required for the management of CCRs under the RCRA that the Company is seeking recovery of can be found in Exhibits A-12 (RTB-3), Schedule B-5.1, and A-41 (RTB-4). Separately, there are closure activities that will continue throughout the test year and beyond; however, those expenses are Cost of Removal and are not included in this filing.

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-5.1, Generation Capital Expenditures.

A. This exhibit presents the capital expenditures for Generation, 2022 through the projected test year - 12 months ending February 28, 2025. Exhibit A-12 (RTB-3), Schedule B-5.1, is a 10-page exhibit. Page 1 of this exhibit presents a summary of Generation capital expenditures for the Historical Period ended December 31, 2022, the Projected 14-month Bridge Period beginning January 1, 2023 and ending February 29, 2024, and the projected test year beginning March 1, 2024 and ending February 28, 2025. 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 is 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. Page 7 of this exhibit provides a summary of Non-Environmental and All Other Environmental capital expenditures in the Projected 14-month Bridge Period ending February 29, 2024 and the projected test year ending February 28, 2025. Finally, 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 approval[2], 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.

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[2] 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.

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); $1,370,168[3] 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.

Q. Please explain how the Company prioritizes its capital investments within Generation.

A. In evaluating capital investments, the Company's first priority is addressing safety, regulatory, compliance, and continued operation related projects. These projects are considered a mandatory cost of doing business. Safety, regulatory, compliance, and continued operation-related projects provide economic value to customers in that they allow the units to remain in service and avoid potential derates and/or shutdown due to an intervention by various regulators including Occupational Safety and Health Administration ("OSHA"), the EGLE, the EPA, and FERC. In order to minimize the impact of these projects on customers, the Company utilizes a least cost/best fit ("LCBF") for the investments necessary to satisfy service quality, safety, and Federal and State policy requirements.

Q. How does the Company determine whether other projects get approved for funding?

A. In accordance with the Company's generation asset strategy for each generating unit or category of generating units, economic projects that are expected to reduce ROR, maintenance cost or heat rate, all else being equal, are evaluated to ensure that their implementation results in a net benefit to the customer. For a project to receive approval for implementation, the projected benefits of the work must have a greater value than the cost of implementing the project. In other words, the implementation of the project should, at a minimum, result in a marginal customer benefit.

Q. How does the Company evaluate other capital investments, such as economic projects?

A. The Company uses two financial measures, Internal Rate of Return ("IRR") and Present Value Ratio ("PVR"), as a means to evaluate and prioritize projected economic projects within Generation. A complex financial model was developed in-house that allows the Company to calculate and measure the numerous changes that result when improvements (both O&M and Capital) are made to its rate-based generating units.

Q. Does the Company calculate IRRs or PVRs for all projects?

A. No. The Company calculates IRRs or PVRs for economic projects that are not considered required but would yield net benefits to customers. Projects required for regulatory, compliance, and/or continued operations are reviewed to assure that the project is cost effective and result from a reasonable evaluation of alternatives, but because the project must be done for compliance and continued operation, IRR or PVR may not be calculated. When evaluating project alternatives related to regulatory, compliance, and/or continued operations, IRRs or PVRs may be used to rank alternatives.

Q. Please explain what you mean by projects for continued operations.

A. Projects for continued operations refers to projects which are necessary to allow the generating unit to continue to operate through its retirement date. Alternatives for projects necessary for continued operation will generally be evaluated based upon LCBF. For this evaluation, one of the alternatives will include a decision to not perform the project and either retire the unit earlier than projected or operate the unit at a permanent derate.

Q. How does the Company evaluate customer benefits associated with generation-related capital investments?

A. The Company uses replacement power cost estimates and PSCR impacts when evaluating customer benefits. The Company also evaluates ROR and heat rate improvements, which result in increased and/or lower cost generation.

Q. How does the Company evaluate historical events which have impacted availability?

A. The cause of each of the historical events impacting availability are evaluated and measured, and the actions necessary to avoid the same or similar events are considered for implementation. In many cases, actions necessary to prevent the event from recurring are cost beneficial. The availability projections, including ROR, simply reflect the Company's best estimate of the operational benefits of those corrective actions that have already been taken or are planned to be taken, through the projected test year ending February 28, 2025.

Q. Does the Company evaluate customer benefits associated with Outage Schedules?

A. Yes, the Company uses historical market prices to evaluate timing around outages, in an effort to ensure the unit is available during periods in which market pricing is projected to be high.

Q. Is it possible that the Company could experience changes to its scheduled outages and forecasted capital expenditures in the future?

A. Yes. The Company often forecasts future actions and capital expenditures based on currently available information, many months before the work is completed. To provide some perspective, the outage schedule used in this case was approved in August 2022. A review of the outage schedule used in this case identifies seven scheduled outages that begin in March 2024 (18 months after the schedule was approved) and run through

February 28, 2025, 29 months later. During each of these seven scheduled outages, Consumers Energy has scheduled a number of tasks to be performed. Because of the long lead times, the number of outages scheduled during the test year, and the fact that several different tasks will be performed during each outage, it is inevitable that some scheduled outages and forecast capital expenditures will change. However, the Company has a history of prudent capital investments in its generating facilities, which have been consistently supported by the Commission.

Q. Are there other reasons why outage schedule changes occur?

A. Yes. Some of the reasons why outage schedule changes occur are: contractor availability, parts availability, changes in regulations, design changes, outage scope changes, changes in unit condition, and spot market prices.

Q. Can you provide an example of when circumstances changed?

A. Yes. The Company's fall 2021 outage for Campbell Unit 1 was originally scheduled from September 24, 2021 through November 8, 2021. The outage was deferred to 2022 due to the higher than projected MISO energy prices and the Company's ability to create economic value for its customers through continued operation of the unit. Campbell Unit 1 provided more that $27 million in NEV to customers during 2021, a portion of which was earned during the originally scheduled outage period. The deferred Campbell Unit 1 outage began on February 27, 2022 and lasted 39 days, ending April 8, 2022. The outage was taken for air preheater basket and seal replacement, pulse jet fabric filter ("PJFF") bag replacement, performance of high energy piping surveillance ("HEPS"), and flow accelerated corrosion ("FAC") inspection.

Q. Please describe how the Company determines its generation projected capital expenditure amounts.

A. Consistent with the Company's generation asset strategy, generation projected capital investments support the continued safe, regulatory compliant, and reliable operations of the Company's generating fleet. Projected capital investments are informed by historical and anticipated performance of the units. The reasonableness of the generation capital investments is indicated by the sustained or improved performance of the Company's generating fleet relative to: (1) the safety of the employees, contractors, and community at and around the generating facilities; (2) compliance with rules and regulations; and (3) reliably participating in the energy, resource adequacy, and ancillary services markets.

Q. How are projects identified that are discussed later in this direct testimony?

A. Generation System Planners assess the equipment performance and compare that assessment with the generation asset strategy for the generating unit. Upon identification of a potential project, the Planner will complete a project initiation document ("PID"). This document defines the issue, alternatives considered for resolution, intended benefits or consequences avoided, and suggested timing and a cost estimate. The document is reviewed by multiple groups for alignment and ultimately routed for approval for inclusion in the Long Term Financial Plan ("LTFP"). PIDs entered into the LTFP will typically be scheduled three to five years in the future to align with outages and provide the project execution teams ample time to plan and engineer.

Q. How were the projected capital expenditure amounts developed for each of the projects discussed later in this direct testimony?

A. Each project begins with the creation of a PID. The Planner will provide an initial cost estimate for the project within the PID. The Planner utilizes past experience, contractor cost estimates, internal estimates, Original Equipment Manufacturer ("OEM") data, and studies to provide the best estimate of the costs. This activity typically takes place three to five years prior to the start of project execution.

Q. How are PIDs related to Concept Approval Documents ("CADs")?

A. The PID is the mechanism utilized to allow projects to be considered for the LTFP. Once the project is included in the LTFP and the project is within a year of start of execution, the CAD is created. The CAD is templated from the PID and updated as necessary. The CAD is then routed for approval to the designated level of management based on project amount and, once approved, the project will be initiated.

Q. Do adjustments to the projected capital investment amounts for each of the projects occur prior to project implementation?

A. Yes. As the project team progresses through the life cycle of a project, there are multiple opportunities to better define project costs. Activities such as detailed engineering, bidding, contractor involvement, and construction all allow for budgets to be better defined. As this definition evolves, the projected capital investments are updated accordingly.

2022 HISTORICAL TEST YEAR CAPITAL EXPENDITURES

Q. How does the 2022 actual capital expenditure amount of $141.372 million compare to the amount of capital expenditures reflected in the Company's request in Case No. U-21224?

A. The 2022 actual capital expenditure amount of $141.372 million is $76.480 million below the Company's requested amount in Case No. U-21224. As is discussed later in this direct testimony, the reduction in the Company's actual capital expenditure amount is directly attributable to spending approximately $81.4 million less on solar projects than projected. It is important to note that the projected solar project capital expenditures were not projected to close by the end of the projected test year and were offset by the allowance for funds used during construction ("AFUDC"). As such, the underspend did not impact the revenue requirement. The Company's as-filed 2022 projected capital expenditure amount of $210.910 million was adjusted to $217.852 million in the Company's rebuttal testimony to remove several projects at the Jackson Plant, as they were no longer required, and add several projects at Karn Units 3 and 4 due to the 2021 IRP settlement agreement which continued the operation of Karn Units 3 and 4 through 2031. A compilation of the 2022 projects which have actual capital expenditure amounts greater than $1 million is presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 8.

Q. How does the compilation of capital projects on Exhibit A-12 (RTB-3), Schedule B-5.1, page 8, compare with the 2022 capital projects reflected on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 7?

A. A comparison of the projects on Exhibit A-12 (RTB-3), Schedule B-5.1, page 8, with the 2022 projects reflected on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 7, reveals that there are six projects on Exhibit A-12 (RTB-3), Schedule B-5.1, page 8, which were not reflected on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 7. In addition, there were three projects for 2022 that were reflected on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 7, that are not presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 8.

Q. Please discuss the 2022 capital projects that were included on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 7, that are not presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 8.

A. The following projects are not presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 8, due to the fact that their actual 2022 capital expenditure amount was less than $1 million or the project was not pursued in 2022. The disposition of these capital projects is below:

- Foote Trash Rack Ergonomics ($2,675,000). This project began in 2022 at an actual cost of $793,452. This project is scheduled to be completed in 2024 at a projected cost of $1,466,667 as discussed in the direct testimony of Company witness Monroe;

- 2019 IRP Solar Bid Event ($63,593,000). The actual 2022 capital expenditure was $162,468. A thorough discussion of this project's status is presented in Company witness Clark's direct testimony; and

- 2020 IRP Solar Bid Event ($40,909,000). The actual 2022 capital expenditure was $147,697. A thorough discussion of this project's status is presented in Company witness Clark's direct testimony.

Q. Please discuss the 2022 capital projects that were not included in Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 7, that are presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 8.

A. The disposition of these capital projects is presented below:

- Campbell Unit 3 Diesel Generator Controls ($1,172,322). This project was scheduled for 2022 but the project estimate was only $186,620. The project costs increased because the original estimate did not include the engineering and integration costs. While the Company had anticipated using a single vendor 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.

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 contingency and the total actual capital expenditures for the projects presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 8, is $118.365 million, a reduction of $59.610 million. An evaluation of the 2022 projects included on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 7, against the actual costs for those projects reveals that with the exception of projected costs for the 2019 and 2020 solar bid event projects (underspent by more than $81 million), the reduction in the spend for the Karn unit separation project ($5.602 million), and the 2021 solar bid event project (overspent by $22.789 million), the projected spending for the large projects was on target. A discussion of the 2019, 2020, and 2021 solar bid event projects (i.e. the Mustang Mile Solar Project, the Washtenaw Solar Project, and the Muskegon Solar Project) is included 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, impact the 2022 total projected capital expenditure amount of $217.852 million?

A. The $59.610 million decrease in capital expenditures from the $177.975 million net of contingency for the projects presented on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 7, versus the $118.365 million for the projects presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 8, helps explain the difference in the capital expenditure amount of $217.852 million requested in Case No. U-21224 Exhibit A-225 (SAH-7) and the actual 2022 capital expenditure amount $141.372 million requested in this proceeding. The actual amount spent for the Karn Units 3 and 4 separation project, and the actual amount spent for three Hardy projects (discussed later) makes up a majority of the remaining difference.

Q. Were there any major 2022 projects whose capital expenditures were contested and/or not fully included in the Case No. U-21224 Settlement Agreement?

A. Yes. The 2022 projected capital expenditures for three projects at Hardy, (1) Auxiliary Spillway Replacement, (2) Crest Roadway Replacement and Compaction, and (3) Splash Wall Replacement, were limited to engineering costs only, or $5.3 million. The total amount reflected in the Company's original request for recovery was $8.26 million, and the actual 2022 amount for engineering costs totaled $4.057 million.

Q. Did the Case No. U-21224 Settlement Agreement establish other limitations or requirements for the Company's hydroelectric generating facilities?

A. Yes. In addition to the capital expenditure limitation for 2022 as discussed above, the Settlement Agreement limited 2023 cost recovery to projected engineering costs totaling $3.45 million. Further, the Settlement Agreement required the Company to collaborate with the MPSC Staff and the Attorney General to both scope and conduct various analyses of all reasonable options to remediate the condition of the Hardy Dam, prior to commencing construction of the Hardy Dam upgrades.

Q. What specific analyses will be performed?

A. The analyses will include the development of economic business cases for the Hardy Dam which will consider, at a minimum, the feasibility and impacts of (1) full decommissioning and removal, (2) divestiture, (3) permanently lowering the reservoir height, and (4) any other reasonable options that lead to a reduced impact of the Hardy Dam on customer rates. These economic business cases are required to be performed by an external engineering firm with experience in the engineering, construction and decommissioning of dams. Specifically, the economic business cases will assess the value of the energy and capacity that Hardy Dam will provide customers, under a variety of reasonable assumptions, against the revenue requirement associated with the projected capital expenditures and O&M expenses through 2034, the end of Hardy Dam's current FERC license term.

Q. Does the Case No. U-21224 Settlement Agreement include other requirements?

A. Yes. The Settlement Agreement also requires the Company to either perform, or cause to be performed, an economic assessment of the impact of the various options on the Muskegon River Hydroelectric Dam communities. In addition, the Settlement Agreement requires the Company to engage in discussions with the affected local communities regarding both the costs and timing of the proposed projects for the Hardy, Croton, and Rogers Dams, and the need for funding, including potential funding mechanisms, from the affected communities. The performance of these discussions with the affected local communities as well as the potential funding from these local communities, must be shared with the Commission prior to commencing construction.

Q. What are the Company's current plans for commencing construction at the Hardy Dam?

A. As is discussed in more detail in Company witness Monroe's direct testimony, the Company's current plans are to begin construction in the fall of 2025.

CONTINGENCY

Q. Has the Company included any contingency in the requested capital expenditures for Generation?

A. No. However, Exhibit A-12 (RTB-3), Schedule B-5.1, page 4, line 5, columns (c) and (d), presents $0.807 million in total contingencies in the 14-month bridge period ending

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 expenditure amounts for which the Company is seeking recovery. Because the Company believes that contingency is a real cost of performing project work, it has presented these amounts in testimony in support of each individual project such that they will align with its concept approval documents. Total contingency is then backed out of capital spending in Exhibit A-12 (RTB-3), Schedule B-5.1, page 1, line 16. Projected capital spending less contingency is then presented on line 17 of this exhibit. The Company is including this capital spending net of contingency in its requested rate relief.

<u>PROJECTED 14-MONTH BRIDGE PERIOD CAPITAL EXPENDITURES</u>

Q. How does the projected 14-month bridge period capital expenditure of $1,370 million compare to the amount of capital approved by the MPSC in Case No. U-21224 for 2023?

A. The 14-month bridge period projected capital expenditure amount of $1,370 million is $107 million more than the projected test year amount of $1,263 million requested in the Company's last electric rate Case No. U-21224. The primary contributors to the increase between the 2023 projected test year amount in Case No. U-21224 and the 14-month projected bridge period amount in this case is a $125 million increase in projected capital expenditures for IRP solar bid events as well as the incremental projected capital expenditure amount of $81 million for the two-month period ending February 29, 2024, as presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 1, line 17, column (d). 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-5.1, page 9.

Q. How does the compilation of 14-month bridge period capital projects on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, compare with the 2023 capital projects reflected on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 8?

A. A comparison of the 14-month bridge period capital projects on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, with the 2023 projects reflected on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 8, reveals that there are 11 projects on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, which were not reflected on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 8. In addition, there were 10 projects for 2023 that were reflected on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 8, that are not presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9.

Q. Please discuss the 2023 capital projects that were included on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 8, that are not presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9.

A. The following projects are not presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, 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 below:

- Campbell Unit 3 Complete Mill Overhauls ($1,295,300). The Company reduced the cost of this project to $552,370 in the 14-month bridge period as part of its capital efficiency efforts which will be discussed in more detail later in this direct testimony. This scope of project will also be discussed in more detail later in this direct testimony;

- Karn Unit 4 distributed control system and simulator upgrade ($1,000,000). The projected cost of this project has been reduced by $100,000 and, as such, is no longer presented on Exhibit A-12 (RTB-3), Schedule B-5.1. The scope of this project is discussed later in this direct testimony;

- Jackson turbine building temperature control replacement ($1,321,968). This project was removed in the Company's rebuttal testimony in Case No. U-21244 due to the current condition of the equipment. The Company invested approximately $100,000 to replace inoperable louvers. As a result of this work, the Company believes that it can invest approximately $20,000 in major maintenance work on an annual basis to keep the turbine building temperature control system operable, thereby obviating the need for this project at this time. The engineering team will re-evaluate this project in the future to ensure annual maintenance resolves the temperature controlling issue and if it is not sufficient, they will develop a future plan and options;

- Alcona Risk Informed Decision Making Resolution ($1,000,000). The projected cost for the bridge period has been reduced to $0.417 million with $2.5 million reflected in the projected test year. The scope of project will also be discussed in more detail later in this direct testimony;

- Alcona Trash Rack Ergonomic Project ($1,160,000). This project has been deferred beyond the test period;

- Foote Governor Replacement ($1,277,000). This project was pulled forward and was completed in 2022 at a total cost of $697,163;

- Loud Spillway Hoist Replacement ($1,043,000). The Company reduced the cost of this project by $50,000 to $993,000 in the 14-month bridge period as part of its capital efficiency efforts which will be discussed in more detail later in this direct testimony. The project is now below the threshold for inclusion on this exhibit. The scope of project will also be discussed in more detail later in this direct testimony;

- Jackson Generator Stator Rewind ($2,400,000). This project was removed in the Company's rebuttal testimony in Case No. U-21224 due to the current condition of the equipment. An inspection performed in Spring 2022 of a corona repair performed in 2021 showed no signs of degradation that would require a stator rewind to be performed in 2023. Another borescopic inspection will be performed in 2024. Beyond 2024, the OEM's in-situ inspections (including visual inspections) will be performed on their five-year planned frequency;

- Webber Unit 1 Overhaul & Generator Rewind ($3,570,000). This project has been deferred to the test period and is discussed in the direct testimony of Company witness Monroe; and

- Zeeland Generator Gas Turbine Rewind ($2,675,000). This project was cancelled and replaced with bridge period projects for the field rewinds at Zeeland Units 3 and 4 which are discussed below in the bridge period project additions and supported later in this direct testimony.

Q. Please identify the 14-month bridge period capital projects that were not included on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 8, that are presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9.

A. The bridge period capital projects that were not included on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 8, include: (1) Karn Units 3 and 4 Tank Farm Storage Tank Heating Line Replacement, (2) Karn Units 3 and 4 Sync Wire Replacement, (3) Zeeland Unit 4 Generator Rotor Field Rewind, (4) Zeeland Unit 3 Field Rewind, (5) Rogers PMF Project, (6) Rogers Unit 4 Generator Rewind, (7) Mio Electrical Safety Project, (8) Webber Left Downstream Spillway Abutment Wall, (9) Ludington Oil Water Separator Replacement, (10) Ludington Distributed Control System ("DCS") Control Relay Replacement, and (11) 2021 Solar Event - Muskegon Solar Project. The basis for projects 1 through 4, 9, and 10 will be discussed in more detail later in this direct testimony, the basis for projects 5 through 8 will be discussed in the direct testimony of Company witness Monroe, and the basis for project 11 will be discussed in the direct testimony of Company witness Clark.

Q. Is the projected capital expenditure amount of $1,370 million for the 14-month bridge period ending February 29, 2024, on Exhibit A-12 (RTB-3), Schedule B-5.1, page 1, column (c), consistent with the Company's generation asset strategy?

A. Yes. Based upon a review of the projected capital expenditure presentation on Exhibit A-12 (RTB-3), Schedule B-5.1, pages 2 and 3, lines 1 through 119, column (h), $417.180 million of that capital will fund solar projects pursuant to the Company's IRP, $882.950 million of that total capital expenditure amount will be used for the acquisition of the Covert Plant and projects at the Covert, Jackson, and Zeeland plants. Furthermore,

$13.794 million will fund various projects at the LPS, and $36.662 million will fund various hydro safety, reliability, and regulatory compliance projects. With the exception of the solar projects and the river hydro projects, a detailed discussion of the various projects for each generating unit or group of generating units will be provided later in this direct testimony. The river hydro projects will be discussed in the direct testimony of Company witness Monroe and the solar projects will be discussed in the direct testimony of Company witness Clark.

Q. Do the Company's projected capital expenditures at the Campbell site for the 14-month bridge period ending February 29, 2024, align with the Company's generation asset strategy and the planned retirement of the generating units at that site?

A. Yes. The Company's projected capital expenditures for Campbell Units 1, 2, and 3 for the 14-month bridge period ending February 29, 2024 are significantly reduced from the five-year average capital expenditure amount for the period from 2018 through 2022. The 14-month bridge period capital expenditures for Campbell Units 1 and 2 represents an 87% reduction from the five-year average, the 14-month bridge period projected capital expenditures for Campbell Unit 3 represents a 50% reduction from the five-year average.

PROJECTED TEST YEAR CAPITAL EXPENDITURES

Q. Is the projected capital expenditure amount of $387.888 million for the test year ending February 28, 2025, on Exhibit A-12 (RTB-3), Schedule B-5.1, page 1, column (d), consistent with the Company's generation asset strategy?

A. Yes. Based upon a review of the projected capital expenditure presentation on Exhibit A-12 (RTB-3), Schedule B-5.1, pages 2 and 3, lines 1 through 119, column (j),

$269.457 million of that capital will fund solar projects pursuant to the Company's IRP and $47.281 million of that total capital expenditure amount will be used for projects at the Covert, Jackson, and Zeeland plants. Furthermore, $14.137 million will allow the Company to complete various regulatory, reliability, and infrastructure projects necessary to support the 50-year license extension at Ludington granted by FERC in 2019 and $49.897 million will fund various hydro safety, reliability, and regulatory compliance projects. Except for the solar projects and the river hydro projects, a detailed discussion of the various projects for each generating unit or group of generating units will be provided later in this direct testimony. The river hydro projects will be discussed in the direct testimony of Company witness Monroe and the solar projects will be discussed in the direct testimony of Company witness Clark.

Q. Do the Company's projected capital expenditures at the Campbell site for the test year ending February 28, 2025 align with the Company's generation asset strategy and the planned retirement of the generating units at that site?

A. Yes. As previously discussed, the Company's projected capital expenditures for Campbell Units 1, 2, and 3 for the test year ending February 28, 2025 are significantly reduced from the five-year average capital expenditure amount for the period from 2018 through 2022. The test year projected capital expenditures for Campbell Units 1 and 2 represents a 98% reduction from the five-year average, the test year projected capital expenditures for Campbell Unit 3 represent a 96% reduction from the five-year average.

<u>Campbell Units 1 and 2</u>

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 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 more detailed discussion of these projects will be provided later in this direct testimony in the discussion of Campbell Site Commons projects.

Campbell Unit 3

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 Unit 3.

A. The Company plans to invest a total of $5.138 million in 14-month projected bridge period and $0.378 million in the projected test year at Campbell Unit 3. The 14-month projected bridge period amount includes $2.437 million in non-environmental expenditures and $2.700 million in environmental expenditures and the projected test year amount includes $0.360 million in non-environmental expenditures and $0.018 million in environmental expenditures. The non-environmental amounts are shown on both Exhibit A-12 (RTB-3), Schedule B-5.1, page 2, line 8, columns (h) and (j), respectively, and Exhibit A-12 (RTB-3), Schedule B-5.1, page 7, line 3, columns (b) and (d), respectively, and the environmental amounts are shown on Exhibit A-12 (RTB-3), Schedule B-5.1, page 7, line 4, columns (c) and (e), respectively. These capital investments will be facilitated by outages in the spring of both 2023 and 2024. The Campbell Unit 3 outage scheduled for the spring of 2024 is presented on Exhibit A-39 (RTB-1), line 4.

Q. What is the basis for the projected $5.138 million capital expenditure amount for the 14-month projected bridge period?

A. The projected $5.138 million capital expenditure amount will fund regulatory compliance and reliability projects. One of those projects is greater than $1 million and is presented 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-O_2 monitor replacement ($223,944). This project began in 2021 and its scope includes the replacement of the existing O_2 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;

- 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.

Q. What is the basis for the projected $0.378 million investment in 2023?

A. The projected $0.378 million investment will fund three projects which are common to the Campbell site. This projected amount reflects a 57% allocation of the total amount, which is $662,918. These projects include fuel handling dust collector bag replacement, dry ash landfill closure, and machine shop replacement. The funding for the machine shop replacement will evaluate and engineer the various alternatives for moving/replacing the existing machine shop at the Campbell site. The machine shop provides timely and cost-effective solutions to parts and equipment needs at the Company's generating facilities.

<u>Covert Plant</u>

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 Covert.

A. The Company plans to invest a total of $829.095 million in the 14-month bridge period and $20.274 million in the test year at the Covert Plant. These capital investments will be facilitated by 19-day outages at Covert Units 1 through 3 in October and November 2024.

Q. Please explain the Company's projected capital investment for the 14-month bridge period ending February 29, 2024 for the Covert Plant.

A. The Company plans to invest a total of $829.095 million in the bridge period on the Covert Plant, as shown on Exhibit A-12 (RTB-3), Schedule B-5.1, page 2, line 43, column (h).

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:

- 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.

<u>Karn Units 1 and 2</u>

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.

<u>Karn Units 3 and 4</u>

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 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:

- Karn Units 3 and 4 Ductwork Expansion Joint Replacement – Induction Draft ("ID") Fans to Stack ($950,000). 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 Karn Units 3 and 4. 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;

- Karn Unit 4 DCS and Simulator upgrade Evergreen ($900,000). 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;

- Karn Unit 3 DCS & Simulator Evergreen ($540,000). 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;

- BOP Capital tooling/valves/instrumentation ($891,667). 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; and

- Five additional projects at Karn Units 3 and 4 totaling $0.700 million which support safety, security, and reliability, with each project representing $185,000 or less in capital expenditures. These projects include replacement of Karn

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.

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

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 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:

- 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

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 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.

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 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.

Q. What is the basis for the projected $11.720 million capital investment in the projected test year?

A. The projected $11.720 million capital investment in the projected test year 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-5.1, page 10, lines 3 and 4. The basis for these projects is described below:

- Jackson Plant LTSA ($8,244,761). 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 Jackson Plant is comprised of nine generating units. Units 1 through 6 are GE Model LM6000PC Gas CTG each with a HRSG attached to the exhaust of the Combustion Turbine. Unit 7 is a GE Model Frame 7EA CTG with a HRSG, and Units 8 and 9 are GE STGs powered by the steam created from the 7 HRSGs. 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, address 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; and

- Jackson Plant Units 1 – 6 SAC Extended Life Combustor ($1,338,458). The scope of this project is to remove the G42 combustor and replace it with the new Rich Quench Mixture ("RQM") combustor during hot gas path inspections. Specifically, this project will perform an operational study to operate a RQM combustor in a steam/gas configuration and attempt to achieve 15 ppm NO_x. The study will be to install an RQM combustor on 1 of the 6 LM6000s. If the operational study proves to be successful, an RQM combustor would then be installed on all LM6000 units. There are 7 total, 6 in service and 1 spare.

  The Jackson Plant's LM6000 units currently utilize a G42 Jet-Rad combustor. In recent years, the OEM developed the Rad-Rad (G48) design combustor to increase the longevity of primary and secondary swirlers by improving the materials to prevent or reduce their cracking over time and reduces thermal barrier coating loss on high pressure turbine stage 1 blades. More recently, the RQM combustor has been introduced by GE. The RQM 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.

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.

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 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.

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

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, CO^2 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 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 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 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 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 entrainment. 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.

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

- 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.

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, page 10, lines 25 through 27. The basis for those projects is described in the direct testimony of Company witness Clark.

Q. Are you supporting any other projected capital expenditures for generation related projects in the test year ending February 28, 2025?

A. Yes. I am also supporting an Information Technology ("IT") project, Generation Operations Digital Work Management. The test year projected capital expenditure amount is $1.379 million, and the test year projected O&M expense amount is $0.110 million. These amounts are reflected in the exhibits of Company witness Heather M. Weller. The scope of this project is to provide durable mobile devices, software, and digital forms for Electric Generation at LPS, wind parks, and hydro facilities.

Q. What are the benefits of this technology project?

A. This project will provide faster retrieval and updates of procedures, equipment statistics, work order data, and time entry. The current work management process for Electric Generation at the wind parks, hydro facilities, and LPS is cumbersome and largely paper based outside of desktop kiosks; resulting in process waste, re-work, and human error. This project provides benefits through: (1) increased productivity by reducing the need to return to the desktop kiosk for updates; (2) improved quality through increased accuracy of updates completed at the time and place of the work; and (3) improved safety through real-time information used at work sites rather than printed procedures or drawings.

Q. What is the specific scope of the project?

A. The specific scope of the project includes the initial roll out for Electric Generation at LPS, wind parks, and hydro facilities, which would include mobile devices, software, and enhanced wireless connection.

Q. Did the Company consider alternatives for this project?

A. Yes. The alternatives considered include: (1) Utilize an SAP work management mobile solution. An SAP work management solution is not preferred since it is a new solution and requires additional project and support cost; (2) Continue the manual paper-based process. Continuing the manual paper-based process was not chosen because of process waste, re-work, and human error; (3) Customize the existing electronic Shift Operations Management System ("eSOMS") mobile application to add work management functions. A custom eSOMS mobile application was not chosen because it would require additional project cost and an ongoing support budget for a custom solution that the eSOMS product was not intended to support; (4) Utilize the existing Service Suite solution currently deployed for Gas and Electric Distribution in combination with digital forms. The combined Service Suite and digital form solution is the preferred option because it is a proven solution at the Company and provides the mobility and digital benefits at a lower cost.

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 and Monroe provide additional discussion in their 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, 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

- 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;

(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.

Q. Please explain Exhibit A-41 (RTB-4), page 2.

A. Exhibit A-41 (RTB-4), page 2, presents the amounts of the projected O&M expenses that were developed by applying either an inflation rate or contract rate to historical O&M expense. Column (b) presents the historical O&M expense. Column (c) presents the amount of the historical O&M amount to which an inflation rate or contract rate applies. Columns (e) and (g) present the amounts to which an inflation rate or contract rate were applied for each period, respectively. Columns (d), (f), and (h) present contract and inflation increases for each respective period. Amounts that were projected using other methods are included in column (i). Column (j) is the projected test year O&M and is the sum of columns (b), (d), (f), (h), and (i).

Q. Please explain how the various inflation and contract rates were applied to Labor, Material, Contractor, and Non-Labor Other O&M expense on Exhibit A-41 (RTB-4), page 2.

A. The historical labor on line 1, column (b) reflects a combination of both Operating Maintenance and Construction ("OM&C") and non-represented labor. Inflation rates of 3.9%, 2.2%, and 2.1% were applied to labor on line 1, material on line 2, contractor on line 3, and non-labor other on line 4 to develop the annual increase amounts in columns (d), (f), and (h).

Q. Please discuss how the adjustments on Exhibit A-41 (RTB-4), page 2, column (i) were determined.

A. As previously discussed, the Company projects the future maintenance needs of each unit. The test period projected O&M expense amount of $164.252 million reflects that evaluation. Within the test period projected amount of $164.252 million, there is one 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

$12.002 million as compared to the projected test year capital expenditures of $0.631 million.

ENVIRONMENTAL OPERATIONS

Q. What are Environmental Operations expenses?

A. Environmental Operations expenses consist of labor and materials supporting the operations of the Company's AQCS. As Federal and State emissions 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. Now that the Company has experienced multiple calendar years of operation, the Company anticipates these expenses to remain relatively consistent going forward. However, because the cost to operate and maintain these critical pieces of equipment is directly related to the operation of the coal-fired power plants they support, yearly variances in the total Environmental Operations expense should be expected based on the operation of the coal plants in a given year.

Q. Please explain how the projected Environmental Operations expenses for the projected bridge period ending February 29, 2024 and test year ending February 28, 2025 were calculated.

A. Environmental Operations expenses are a combination of O&M costs related to the environmental equipment at the Karn and Campbell sites. The operations component is primarily calculated using labor costs for operations and environmental waste disposal. The maintenance component is based on a combination of historical and estimated planned maintenance costs on the specific components of environmental equipment. 2022 was the sixth full year of operations of the environmental equipment at both Campbell and Karn, and the Company now has robust historical data to use in projecting these expenses. However, as reflected on Exhibit A-41 (RTB-4), page 1, line 3, columns (b) and (d), the walk from the 2022 historical expense of $10.802 million to the projected test year expense of $5.860 million reflects a cost reduction of $4.942 million despite inflationary increases. This cost reduction is a direct reflection of the retirement of Karn Units 1 and 2 on May 31, 2023.

MAJOR MAINTENANCE

Q. What are Major Maintenance expenses?

A. Major Maintenance represents O&M projects that are based on asset condition or on historic maintenance intervals over multiple years. To maintain and improve the performance of generating fleet, the Company performs Major Maintenance on a regular basis. However, completion of Major Maintenance work can be influenced by, among other things, actual operations of the generating units, availability of parts and labor, and energy market conditions.

Q. Please explain how the Major Maintenance O&M expenses for the projected bridge period ending February 29, 2024 and test year ending February 28, 2025 were determined.

A. Major Maintenance expenses are determined by tracking both the historical and future maintenance needs for each site and unit, considering operation safety, unit reliability, and maximum customer value. Individual projects are calculated in a manner similar to capital projects, as discussed earlier in this direct testimony.

Q. Please identify the 2023 test year Major Maintenance O&M expenses.

A. The Company projects that it will incur $31.976 million in Major Maintenance O&M expenses during the test year, as identified by Exhibit A-41 (RTB-4), page 1, line 4, column (d). Test year Major Maintenance expense by generating unit is presented on Exhibit A-41 (RTB-4), page 3, column (d).

Q. Why is Consumers Energy spending $31.976 million in Total Major Maintenance O&M expense during the projected test year ending February 28, 2025?

A. The Company is spending the majority of its Total Major Maintenance expense during the test year to maintain reliability. Reliability related Major Maintenance O&M expenses, made predominantly during scheduled outages, allow the plants to avoid equipment issues that would lead to more frequent random outages, exposing customers to potentially more expensive replacement energy at market prices. Minimizing forced outages by maintaining equipment improves the likelihood the unit will be available when needed, thereby minimizing damage that could result in catastrophic failure.

Q. Are Major Maintenance expenses relatively consistent from year to year?

A. No. Although the Company attempts to plan for controlled and consistent levels of Major Maintenance, because Major Maintenance outages occur relatively infrequently, for an individual unit, it is very possible to have significant year-by-year variations in the number, duration, and magnitude of the required Major Maintenance work. Other factors such as unforeseen equipment failure, emerging industry initiatives, unit dispatch, expected power prices, unit performance, and simple timing variations can impact the cost and scheduling of Major Maintenance.

Q. Is it possible that changes to the Company's forecasted Major Maintenance plan could occur?

A. Yes. It is possible that the Company's forecasted Major Maintenance plan could change. Equipment condition can change such that the timing of maintenance activities may need to be accelerated or delayed. The Company attempts to make the best decision in balancing the cost and risks associated with the operation of the equipment and attempts to minimize the cost to customers. Factors such as weather, equipment and labor availability, energy market conditions, and electrical system stability considerations can affect the actual timing of an outage and maintenance spending.

Q. Do Major Maintenance costs vary by individual generating unit(s)?

A. Yes. As the Company's generating units vary in age, size, type, and design, so do the costs to maintain these units. As an example, Major Maintenance of Campbell Unit 3 coal pulverizers (785 MW) would be considerably larger in scope and cost than Major Maintenance of Campbell Unit 1 coal pulverizers (260 MW), which is located on the same site.

Q. Is it common for an electric utility to have different sizes, types, designs, and dispatch of generating units in its generation portfolio?

A. Yes. Consumers Energy is not unique in that its fleet contains units of different size, type, and design.

Q. What are the categories of Major Maintenance?

A. Major Maintenance is broken into two categories—outage and non-outage.

Q. Please describe what is included in the outage major maintenance O&M expense.

A. Outage major maintenance O&M expenses are those associated with major overhauls and require that the generating unit be removed from service for boiler and/or turbine inspections and maintenance. These outages are typically scheduled on a periodic basis and are required by law, insurance providers, and/or industry standards to ensure operational safety and reliability. One example of a major maintenance outage is the periodic disassembly and repair of turbine control and stop valves. The valves control the amount of steam going to the turbine and are needed to control the unit output. During an emergency situation, for example during unit electrical trip, the valves must react very quickly to stop the steam going to the turbine to prevent it from overspeeding. Overspeeding the turbine can result in severe mechanical damage resulting in a very long duration outage to repair, further resulting in increased cost to customers for market priced electricity during the outage. Periodic maintenance of turbine valves is required for personnel and equipment safety. Maintaining the valves on a periodic basis ensures that the clearances and internal components operate as designed and can reliably stop the turbine quickly when needed to prevent turbine or generator damage.

Q. Please describe the work completed in a boiler inspection.

A. Boiler inspections assess the fire (outside) and steam (inside) sides of boiler tubing for weaknesses that will ultimately result in water/steam leaks. After the boiler has been properly opened, ventilated, and cleaned, scaffolding is constructed inside the boiler to provide access to the boiler tubes. Inspections are completed using a number of different methods – visual, non-destructive, and destructive. Visual and non-destructive testing are the most common methods of inspection. Non-destructive testing incorporates the use of ultrasonic, x-ray, magnetic particle, or like technologies to measure pipe wall thickness. Boiler tubes that are in poor condition or exceed minimum wall thickness are repaired or replaced. After all repairs are complete, boiler tubes are pressure tested. Each boiler is inspected on a specific time schedule, with a one-, two-, or three-year maximum interval. Internal components with known problems are inspected more frequently. External inspections are performed daily by Generation Operations and annually by state inspectors.

Q. Please describe the work completed in a turbine inspection.

A. Turbine inspections consist of disassembling, inspecting, and cleaning the different components of the turbine. During the inspection, worn or damaged parts are repaired or replaced to specific tolerances. Because of the extreme conditions under which these units operate, the demand for uninterrupted power, and dangers associated with operating these large pieces of equipment, industry standards recommend that inspections be completed every seven years.

Q. Please define non-outage maintenance.

A. Non-outage maintenance O&M costs typically do not require the generating unit be removed from service, but they are still critical to the operation of the unit. An example of non-outage maintenance is Mill/Pulverizer maintenance.

Campbell Units 1 and 2 Major Maintenance

Q. Please describe Campbell 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 2, column (d), Campbell Units 1 and 2 Major Maintenance expense is forecasted to be $1.782 million in the projected test year ending February 28, 2025, and includes:

- 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.

<u>Campbell Unit 3 Major Maintenance</u>

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 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.

<u>Covert Plant Major Maintenance</u>

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

- 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;

- 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.

<u>Jackson Plant Major Maintenance</u>

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;

- 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.

<u>**LPS Major Maintenance**</u>

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, 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 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.

<u>Solar Major Maintenance</u>

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.

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.

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 challenge to operating the units both safely and reliably. The retention component utilizes the best practices that the Company employed in retiring the Classic 7.

Q. What is the purpose of the separation component of the Company's plan?

A. When Karn Units 1 and 2 are retired, the Company plans to follow the terms of the collective bargaining agreement for OM&C employees represented by the Utility Workers Union of America ("UWUA"), and the terms of the employee handbook policy and separation plan for non-represented exempt and non-exempt employees. The structure and amount of the severance offers will vary based on employee salary and classification due to differences in the terms of the separation plan covering non-represented employees and the bargaining agreement for UWUA-represented employees. In the event that exempt or non-exempt employees cannot find placement within the Company within 60 miles from their current location, they will be offered involuntary severance in accordance with the terms of the Company's Salaried Separation Plan. The Company's Working Agreement with the UWUA governs separation for OM&C employees who elect to leave the Company rather than accept a new position as well as relocation expenses if they accept a position more than 60 miles away from their current location.

Q. What are the benefit types associated with the Karn retention and separation plan?

A. The Karn retention and separation plan includes three benefit types: retention benefits, severance benefits, and relocation and moving costs.

Q. Please describe the retention benefits associated with the Karn retention and separation plan.

A. The retention benefits associated with the Karn retention and separation plan include three payment components: a signing incentive, annual incentives, and a final retention incentive.

Employees received a signing incentive equal to 15% of their base pay if they signed a retention agreement in October 2019. By signing the retention agreement, the employee agreed to forfeit their transfer rights under the current working agreement (for union employees) or under Company policy (for exempt and non-exempt employees). The employee had to stay at Karn until October 31, 2020 to receive the payment; if the employee stayed until that date, the incentive was paid out to the employee within 30 days. If the employee separated from the Company before October 31, 2020, the employee forfeited the signing incentive.

Employees receive an annual incentive which graduates from 20% to 30% of their base pay for service each November in years 2019, 2020, and 2021, for staying at Karn and rendering service for the next 12 months. The employee must stay at Karn until October 31 of the following year to receive the payment; if the employee stays until that date, the incentive will be paid out to the employee within 30 days. If the employee separates from the Company before October 31 of the next year, the employee forfeits the annual incentive. Eligible employees received their first annual incentive payment in November 2020, a second payment in November 2021, and a third payment in November 2022.

Employees receive a final retention incentive equal to 60% of their base pay on or about July 1, 2023, if the employee is still at Karn. The payment is intended to incentivize employees to stay until the plant goes cold and dark and compensate employees for the service they rendered for the eight months (November 2022 through June 2023) prior to the payment.

Q. Please describe the severance benefits associated with the Karn retention and separation plan.

A. The severance benefits associated with the Karn retention and separation plan include initial recognition of a severance benefit to be paid, recognition of additional severance earned (one week of pay per year of service), and recognition of the accretion of a final severance benefit.

Q. Why does the Company anticipate the need to make severance payments associated with the retirement of Karn Units 1 and 2?

A. The Company is proud of the fact that following the retirement of the Classic 7 in 2016, all Company employees that desired to continue employment with the Company were able to do so. However, the Company is also aware of the fact that it has fewer Company locations (11 within 60 miles of the Karn site) to which employees can relocate, than it did in 2016. As such, the Company has anticipated the need to make severance payments to those employees that cannot find placement. As I previously stated, the Company plans to follow the terms of the collective bargaining agreement for OM&C employees represented by the UWUA, and the terms of the employee handbook policy and separation plan for non-represented exempt and non-exempt employees.

Q. Please explain the relevant details of the collective bargaining agreement for OM&C employees.

A. The collective bargaining agreement for OM&C employees, in Article VII, Section 17, and the Generation Operations Coal Closing Agreement provide that employees will be placed in either a corresponding position, or if none exists, in a vacant position he/she is qualified to perform within 60 miles of his/her current headquarters. Per Article XVII of the collective bargaining agreement, employees who are released due to lack of work, and are not placed as described above, are provided a separation allowance consisting of straight time pay for five regular workdays for each year of continuous service with the Company. Due to the lack of Company locations within 60 miles of Karn Units 1 and 2, as described above, it is anticipated that some employees will be eligible for a separation allowance.

Q. Please describe the Campbell retention plan.

A. The Campbell retention plan is a people strategy that the Company has proposed in its 2021 IRP. As previously discussed, the Company's 2021 IRP PCA reflects the retirement of Campbell Units 1, 2, and 3 on May 31, 2025. This retention plan was proposed in order to retain employees through the closure of the three Campbell units. This strategy is necessary to ensure that the Company can operate the Campbell units safely and reliably through their retirement date. This incentive program is the same program that is currently in place for employees at the Karn site.

Q. What is the purpose of the retention component of the Company's plan?

A. For similar reasons described in the Karn retention plan, the Company has a strong interest in keeping qualified employees working at the Campbell site 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. Similar to the situation at the Karn site, it will be increasingly difficult to hire new employees at the Campbell site 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 challenge to operating the three units both safely and reliably.

Q. What is the purpose of the separation component of the Company's plan?

A. When the Campbell units are retired, the Company plans to follow the terms of the collective bargaining agreement for OM&C employees represented by the UWUA, and the terms of the employee handbook policy and separation plan for non-represented exempt and non-exempt employees. The structure and amount of the severance offers will vary based on employee salary and classification due to differences in the terms of the separation plan covering non-represented employees and the bargaining agreement for UWUA-represented employees. In the event that exempt or non-exempt employees cannot find placement within the Company within 60 miles from their current location, they will be offered involuntary severance in accordance with the terms of the Company's Salaried Separation Plan. The Company's Working Agreement with the UWUA governs separation for OM&C employees who elect to leave the Company rather than accept a new position as well as relocation expenses if they accept a position more than 60 miles away from their current location.

Q. What are the benefit types associated with the Campbell retention plan?

A. Similar to the Karn retention and separation plan, the Campbell retention plan includes three benefit types: retention benefits, severance benefits, and relocation and moving costs.

Q. Please describe the retention benefits associated with the Campbell retention plan.

A. The retention benefits associated with the Campbell retention plan include three payment components: a signing incentive, periodic incentives, and a final retention incentive. The timeline for retention benefits reflects approval of the Settlement Agreement in the Company's 2021 IRP in June 2022.

Employees receive a signing incentive equal to 15% of their base pay if they signed a retention agreement in July 2022. By signing the retention agreement, the employee agreed to forfeit their transfer rights under the current working agreement (for union employees) or under Company policy (for exempt and non-exempt employees). The employee must stay at Campbell until October 31, 2022 to receive the payment; if the employee stayed until that date, the incentive was paid out to the employee within 30 days. If the employee separated from the Company before October 31, 2022, the employee forfeited the signing incentive.

Employees receive a periodic incentive which graduates from 20% to 30% of their base pay for service each November in years 2022, 2023, and 2024, for staying at Campbell and rendering service for a certain period. Specifically, for service provided July 2022 through October 2022, employees received 20% of their base pay. For service provided November 2022 through October 2023, employees will receive 25% of base pay. For service provided November 2023 through October 2024, employees will receive 30% of base pay. The employee must stay at Campbell until October 31 of the given year to receive the payment; if the employee stays until that date, the incentive was/will be paid out to the employee within 30 days. If the employee separates from the Company before October 31 of the given year, the employee forfeits the annual incentive.

Employees receive a final retention incentive equal to 60% of their base pay on or about October 31, 2025, if the employee is still at Campbell. The payment is intended to incentivize employees to stay until the plant goes cold and dark and compensate employees for the service they rendered for the 12 months prior to the payment.

Q. Please describe the severance benefits associated with the Campbell retention plan.

A. The severance benefits associated with the Campbell retention plan include initial recognition of a severance benefit to be paid, recognition of additional severance earned (one week of pay per year of service), and recognition of the accretion of a final severance benefit.

Q. Why does the Company anticipate the need to make severance payments associated with the retirement of Campbell Units 1, 2, and 3?

A. The Company is proud of the fact that following the retirement of the Classic 7 in 2016, all Company employees that desired to continue employment with the Company were able to do so. However, the Company is also aware of the fact that it has fewer Company locations (7 within 60 miles of the Campbell site) to which employees can relocate, than it did in 2016. In addition, the Company will also have retired at least two of the Karn generating units in 2023, thereby further reducing the available positions. As such, the Company has anticipated the need to make severance payments to those employees that cannot find placement. As I previously stated, the Company plans to follow the terms of the collective bargaining agreement for OM&C employees represented by the UWUA, and the terms of the employee handbook policy and separation plan for non-represented exempt and non-exempt employees, as previously discussed for the Karn retention and separation plan.

Q. What are the projected costs for the Company's Karn and Campbell Retention and Separation plans?

A. As reflected on Exhibit A-41 (RTB-4), page 1, line 5, the Company incurred actual expense of \$2.339 million in 2022, and is projecting expense of \$14.917 million in the 14-month projected bridge period, and \$18.220 million in the projected test year. The actual 2022 expense of \$2.339 million is based upon expense of \$2.339 million for Karn. The 14-month projected bridge period expense of \$14.917 million is based upon expense of \$4.704 million for Karn and \$10.213 million for Campbell. The projected test year expense of \$18.220 million is based upon expense of \$4.145 million for Karn and \$14.074 million for Campbell.

Q. Is the Company requesting O&M recovery of the \$18.220 million projected amount for the projected test year?

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, 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 2022 through the projected test year ending February 28, 2025 are not included in the Total O&M amounts on Exhibit A-41 (RTB-4), page 1, line 6, columns (b), (c) and (d). Company witness Aponte supports regulatory asset treatment of these expenses in her direct testimony.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Schedule: B-5.1

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-21389
Exhibit No.: A-12 (RTB-3)
Schedule: B-5.1
Page: 1 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
($000)

Line No.	(a) Description	(b) Historical Year 12 Months Ended 12/31/2022	(c) Projected Bridge Period 12 Mos Ended 12/31/2023	(d) Projected Bridge Period 2 Mos Ending 2/29/2024	(e) Projected Bridge Period 14 Mos Ending 2/29/2024	(f) Projected Test Year 12 Mos Ending 2/28/2025
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

Line No.	(a)	(b) Projected 2 Mos Ending 2/28/2023	(c) Projected 12 Mos Ending 2/29/2024	(d) Projected 12 Mos Ending 2/28/2025	(e) Projected 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

Case No.: U-21389
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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) Projected Bridge Year 12 Months Ended 12/31/2022	(c)	(d) Projected Bridge Period 12 Months Ending 12/31/2023	(e)	(f) Projected Bridge Period 2 Months Ending 2/29/2024	(g)	(h) Projected Bridge Period 14 Months Ending 2/29/2024	(i)	(j) Projected Test Year 12 Months Ending 2/28/2025	(k)
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)
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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

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Projected Bridge Year		**Projected Bridge Period**						**Projected Test Year**	
Line No.	**Description**	**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 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

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Summary of Actual and Projected Electric Capital Expenditures
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($000's)

Generation Capital Expenditures

	(a)	(b)	(c)	(d)	(e)
		Projected			
Line No.	Description	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

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Summary of Actual and Projected Electric Capital Expenditures
For the years 2022 through 2025
($000's)

Generation Capital Expenditures

	(a)	(b)	(c)	(d)	(e)
		Projected			
Line No.	Description	2 Mos Ending 2/28/2023	12 Mos Ending 2/29/2024	12 Mos Ending 2/28/2025	26 Mos Ending 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

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Summary of Actual and Projected Electric Capital Expenditures
For the years 2022 through 2025
($000's)

Generation Capital Expenditures

Line No.	(a) Description	(b) Historical Year 12 Months Ended 12/31/2022	(c) Projected Bridge Period 12 Months Ending 12/31/2023	(d) Projected Bridge Period 2 Months Ending 2/29/2024	(e) Projected Bridge Period 14 Months Ending 2/29/2024	(f) Projected Test Year 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) Projected 12 Months Ending 12/31/2023	(c) Projected 2 Months Ending 2/29/2024	(d) Projected 14 Months Ending 2/29/2024	(e) Projected 12 Months Ending 2/28/2025	(f) Projected 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

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Consumers Energy Company
Summary of Projected Electric Capital Expenditures
For the projected test year ending February 28, 2025
($000's)

Generation Capital Expenditures

	(a)	(b)	(c)	(d)	(e)	(f)
		Projected Bridge Period 14 Months Ending 2/29/2024		**Projected Test Year 12 Months Ending 2/28/2025**		
Line No.	**Description**					**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**		$ 3,031		$ 31	

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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) Work Item Description	(g) Projected (1) Contingency	(h) Projected (1) Amount	(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 Generatior Controls	$ 19	$ 187	$ 1,172
6	2023	Coal Generation	Campbell Site Commons	Non-Routine	Condition-based	North and South Piegon 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	
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

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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

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
Line No.	**Calendar Year**	**Tier 1 Portfolio**	**Tier 2 Portfolio**	**Project Type**	**Project Classification**	**Class of Cost Estimate**	**Engineering Internal or External**	**Project Bid Issued**	**Full Internal Budget Approval**	**Work Item Description**	**Planned Amount**	**Project Reduction**	**Contingency Amount**	**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	$ 3,600	$ 1,790	$ -	$ 1,810
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	Hodenpyl	Non-Routine	Condition-based	Class 3	Internal	No	Approved	Hodenpyl 1 Generator Rewind	$ 3,310	$ 210	$ -	$ 3,101
27	Bridge Period	Hydro Generation	Hodenpyl	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	Mio	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**										**$ 1,346,768**	**$ 6,597**	**$ -**	**$ 1,340,171**

Note:
(1) Planned amounts were reduced by project reductions and contingency to arrive at the projected amounts

MICHIGAN PUBLIC SERVICE COMMISSION | Schedule: B-5.1

Case No.: U-21389
Exhibit No.: A-12 (RTB-3)
Schedule: B-5.1

Witness: RTBlumenstock
Date: May 2023

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 contra	$ 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 FFH	$ 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 GSU	$ 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 Replaceme	$ 5,000	-	$ -	$ 5,000
8	Test Year	Hydro Generation	Alcona	Non-Routine	Regulatory	Class 4	Internal	No	Approved	Risk Informed Decision Making Resolutio	$ 2,500	-	$ -	$ 2,500
9	Test Year	Hydro Generation	Alcona	Non-Routine	Infrastructure	Class 3	External	No	Approved	Core Wall Remediation Projec	$ 9,057	$ -	$ -	$ 9,057
10	Test Year	Hydro Generation	Foote	Non-Routine	Condition-based	Class 3	External	No	Approved	Unit 2 Wicket Gates Replacement Projec	$ 1,253	-	$ -	$ 1,253
11	Test Year	Hydro Generation	Hardy	Routine	Safety	Class 3	External	No	Approved	Electrical Safety Projec	$ 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 Projec	$ 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 Rewind	$ 4,750	-	$ -	$ 4,750
16	Test Year	Hydro Generation	Foote	Non-Routine	Safety	Class 3	External	No	Approved	ADA Ramp Investigation and replaceme	$ 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 Projec	$ 3,272	-	$ -	$ 3,272
20	Test Year	Hydro Generation	Cooke	Non-Routine	Condition-based	Class 3	External	No	Approved	Head Gate Replacement Projec	$ 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 Replaceme	$ 2,501	-	$ -	$ 2,501
22	Test Year	Hydro Generation	Ludington Site Commons	Routine	Infrastructure	Class 3	External	No	Approved	Administrative Building Additio	$ 2,714	-	$ -	$ 2,714
23	Test Year	Hydro Generation	Ludington Site Commons	Non-Routine	Regulatory	Class 1	Internal	Yes	Approved	Replace Barrier Net Panels	$ 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

Case No.: U-21389
Exhibit No.: A-41 (RTB-4)
Page: 1 of 3
Witness: RTBlumenstock
Date: May 2023

Consumers Energy Company
Summary of the Generation O&M Expense
For the Years 2022 through 2025
($000's)

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**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Inflation
For the Years 2022 through 2025
($000's)

Case No.: U-21389
Exhibit No.: A-41 (RTB-4)

Witness: RTBlumenstock
Date: May 2023

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	Description	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

Case No.: U-21389
Exhibit No.: A-41 (RTB-4)

Witness: RTBlumenstock
Date: May 2023

Consumers Energy Company
Summary of the Generation Major Maintenance O&M Expense
For the Years 2022 through 2025
($000's)

GENERATION MAJOR 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	**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**