Consumers Energy
Count on Us®

October 11, 2021 Electronically Submitted via MiWaters

Michigan Department of Environment, Great Lakes, and Energy
Water Resources Division, Ms. Chris Veldkamp
State Office Building
350 Ottawa Ave NW, Unit 10
Grand Rapids, MI, 49503

RE: NOTICE OF PLANNED PARTICIPATION PURSUANT TO 40 CFR 423.19(f)
CONSUMERS ENERGY COMPANY, J.H. CAMPBELL COMPLEX NPDES PERMIT NO. MI0001422,
STEAM ELECTRIC EFFLUENT LIMITATION GUIDELINES

Dear Ms. Veldkamp,

Consumers Energy Company (Consumers) is submitting this Notice of Planned Participation (NOPP) for the J.H. Campbell (Campbell) Complex, NPDES Permit No. MI0001422. According to 40 CFR 423.19(f)(1) of the Steam Electric Effluent Limitation Guidelines (ELG), sources seeking to qualify as an electric generating unit that will achieve permanent cessation of coal combustion by December 31, 2028, shall file a NOPP to the permitting authority no later than October 13, 2021. Consumers is submitting the following information to support the requirements for Campbell Units 1, 2 and 3 that will achieve permanent cessation of coal combustion by December 31, 2028.

Pursuant to 40 CFR 423.19(f)(2), a NOPP shall do the following:

- Identify the electric generating units intended to achieve the permanent cessation of coal combustion.

- Include the expected date that each electric generating unit is projected to achieve permanent cessation of coal combustion, whether each date represents a retirement or a fuel conversion, whether each retirement or fuel conversion has been approved by a regulatory body, and what the relevant regulatory body is.

- Include a copy of the most recent integrated resource plan for which the applicable state agency approved the retirement or repowering of the unit subject to the ELGs, certification of electric generating unit cessation under 40 CFR 257.103(b), or other documentation supporting that the electric generating unit will permanently cease the combustion of coal by December 31, 2028. See **Attachment A**.

Consumers Energy
1945 W. Parnall Road
Jackson, MI 49201
www.consumersenergy.com

Environmental Services

- Include, for each such electric generating unit, a timeline to achieve the permanent cessation of coal combustion. Each timeline shall include interim milestones and the projected dates of completion. See **Attachment B**.

Electric Generating Units Intended to Achieve Subcategory

A NOPP shall identify the electric generating units intended to achieve the permanent cessation of coal combustion.

Consumers submitted an Integrated Resource Plan (IRP) to the Michigan Public Service Commission (MPSC) on June 30, 2021 in U-21090 proposing retirement of Campbell Units 1, 2, and 3. The following table provides detail of the units to be retired.

Electric Generating Unit	Nameplate Capacity (MW)
Campbell Unit 1	265.2
Campbell Unit 2	403.9
Campbell Unit 3	916.8

Expected Date of Permanent Cessation

A NOPP shall include the expected date that each electric generating unit is projected to achieve permanent cessation of coal combustion, whether each date represents a retirement or a fuel conversion, whether each retirement or fuel conversion has been approved by a regulatory body, and what the relevant regulatory body is.

As stated in the IRP, Consumers proposes retirement of Campbell Units 1, 2, and 3 by May 31, 2025. The table below provides additional details.

Electric Generating Unit	Permanent Cessation Date	Retirement or Fuel Conversion	Approved by Regulatory Body	Regulatory Body
JHC Unit 1 JHC Unit 2 JHC Unit 3	May 31, 2025	Retirement	IRP Submitted June 30, 2021, Decision expected on or before June 27, 2022	Michigan Public Service Commission (MPSC)

Integrated Resource Plan

A NOPP shall also include a copy of the most recent integrated resource plan for which the applicable state agency approved the retirement or repowering of the unit subject to the ELGs, certification of electric generating unit cessation under 40 CFR 257.103(b), or other documentation supporting that the electric generating unit will permanently cease the combustion of coal by December 31, 2028.

A copy of the IRP submitted to the MPSC on June 30, 2021 is included in **Attachment A**. Please refer to Section I(5)(i) on page 4 which details Consumers Energy's proposed course of action as it relates to the accelerated retirement of Campbell Units 1, 2, and 3. At the time of this submittal the MPSC is currently reviewing Consumers submission. The MPSC is expected to return a final decision no later than June 27, 2022. Consumers is also in the process of submitting a request to the Midcontinent Independent System Operator, Inc. (MISO) for suspension of operations at Campbell Units 1, 2, and 3. The MISO will determine if there is any power system reliability impacts and is expected to return a final decision no later than 6 months following the date of Consumers Energy's submittal. If approved by both the MPSC and MISO, documentation will be included in the annual progress report required under §423.19(f)(3).

Timeline to achieve the permanent cessation of coal combustion

The NOPP shall also include, for each such electric generating unit, a timeline to achieve the permanent cessation of coal combustion. Each timeline shall include interim milestones and the projected dates of completion.

A timeline with interim milestones to achieve permanent cessation of coal combustion is included in **Attachment B**. As required under 40 CFR423.19(f)(4) this timeline will be updated as part of Consumers annual progress reports.

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If you have any questions or need additional information, please do not hesitate to contact me at (616) 738-5436 or by email at nathan.hoffman@cmsenergy.com or Rachel Proctor at (517) 788-1429 or by email at rachel.proctor@cmsenergy.com.

Sincerely,

Nathan Hoffman
Consumers Energy Company
Plant Business Manager

Electronically Distributed
CC: Ms. Christine Aiello, EGLE WRD, Permit Unit, Constitution Hall, Lansing MI
Ms. Rachel Proctor, Consumers Energy Company
Ms. Kristin Melcher, Consumers Energy Company, Campbell

Attachment A – Consumers Energy Integrated Resource Plan

General Offices:
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June 30, 2021

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

RE: Case No. U-21090 – 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.

Dear Ms. Felice:

Included in this electronic file in the above-captioned case is the **Redacted Version of Consumers Energy Company's Application and Testimony and Exhibits of Consumers Energy Company witnesses Richard T. Blumenstock, Sara T. Walz, Anna K. Munie, Thomas P. Clark, Heather A. Breining, Kevin J. Watkins, Srikanth Maddipati, Jason R. Coker, Jeffrey E. Battaglia, Keith G. Troyer, Norman J. Kapala, Brian D. Gallaway, Carolee Kvoriak, Benjamin T. Scott, Teri L. VanSumeren, Steven Q. McLean, Lakin Garth, Emily A. McGraw, Matthew S. Henry, Eugene M. Breuring, Teresa E. Hatcher, Nathan J. Washburn, and Sarah R. Nielsen.**

Confidential materials of **Company witness Norman J. Kapala** are being filed under seal with the Michigan Public Service Commission.

In accordance with the filing procedures adopted by the Michigan Public Service Commission in Case Nos. U-15896 and U-18461: (i) copies of the IRP filing are being provided to parties to Case Nos. U-20165, U-20697, and U-20963 electronically and will be made available to all requesting parties to this case, and (ii) the public workpapers of Consumers Energy Company's witnesses are being provided electronically to the Michigan Public Service Commission Staff. This is a paperless filing and is therefore being filed only in a PDF format. I have also enclosed a Proof of Service showing electronic service upon the parties to Case Nos. U-20165, U-20697, and U-20963.

Sincerely,

Robert W. Beach

cc: Parties per Attachment 1 to the Proof of Service

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

APPLICATION

Consumers Energy Company ("Consumers Energy" or the "Company") respectfully requests that the Michigan Public Service Commission ("MPSC" or the "Commission") issue an order approving 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 applicable orders and law. In support of this Application, Consumers Energy states as follows:

I. Introduction

1. Consumers Energy is, among other things, engaged as a public utility in the business of generating, purchasing, distributing, and selling electric energy to approximately 1.9 million retail customers in the state of Michigan. The retail electric system of Consumers Energy is operated as a single utility system, within which uniform rates are charged.

2. Consumers Energy's retail electric business is subject to the jurisdiction of the Commission pursuant to various provisions of 1909 PA 106, as amended, MCL 460.551 *et seq*., 1919 PA 419, as amended, MCL 460.54 *et seq*., and 1939 PA 3, as amended, MCL 460.1, *et seq*. Pursuant to these statutory provisions, the Commission has the power and jurisdiction to regulate Consumers Energy's retail electric rates.

3. On June 15, 2018, the Company filed the first IRP in Michigan under MCL 460.6t in Case No. U-20165. On June 7, 2019, the Commission approved a settlement agreement which was supported, or not opposed, by 20 intervening parties and showed wide support and alignment from many stakeholders to create the best IRP for Michigan. That settlement agreement approved a Proposed Course of Action ("PCA") which became the foundation of the Company's Clean Energy Plan. At a high level, the settlement agreement included the following provisions:

i. The approval of the Company's PCA 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 and a refresh of the evaluation which is to be provided by the Company in a new IRP filing made by June 2021 to continue to show the plan is the most reasonable and prudent means of meeting the Company's energy and capacity needs;

ii. The pre-approval of costs for demand-side management programs in the first three years of the plan (2019-2022);

iii. The accelerated retirement of D.E. Karn ("Karn") Units 1 and 2 in 2023 and for a filing seeking recovery of the unrecovered book balance by no later than May 31, 2023;

iv. A Company-conducted retirement analysis of J.H. Campbell ("Campbell") Units 1 and 2 to be presented in the Company's 2021 IRP;

v. A competitive bidding process to address future capacity needs of the Company during the IRP period and for determining the Company's Public Utility Regulatory Policies Act of 1978 ("PURPA") avoided cost rates. The Company is permitted to use a five-year outlook for determining capacity needs and a PURPA capacity need does not exist for the Company if the Company is implementing its PCA as defined by the competitive bidding process;

vi. A 50% Company ownership and 50% Power Purchase Agreement ("PPA") split of future supply-side capacity acquired through the competitive bidding process;

vii. Approval of a Financial Compensation Mechanism ("FCM") on PPAs approved by the Commission on or after January 1, 2019, excluding Renewable Energy Plan contracts;

viii. Continued collaboration with the local transmission owners, Michigan Electric Transmission Company and ITC Holdings ("METC/ITC"), and with the Midcontinent Independent System Operator, Inc.; and

ix. Various analysis and modeling requirements (i.e. stochastic risk assessment).

4. In accordance with the requirements of the settlement agreement approved in Case No. U-20165, the Company has refreshed its 2018 IRP by reassessing its capacity resource portfolio in light of capacity needs, regulatory and environmental compliance, and the planning objectives set forth by the Commission and the Company. In this case, the Company is seeking approval of an IRP which represents a better plan for Michigan and the most reasonable and prudent means of meeting the Company's energy and capacity needs through 2040. The PCA included in the Company's IRP leads to a faster clean energy transformation by accelerating the Company's exit from coal-fired generation. In addition, through the proposed acquisition of existing gas plants, and the continued commitment to key elements of the Company's Clean Energy Plan, the Company has developed an IRP which does not sacrifice reliability, affordability, or the financial stability of Consumers Energy and which builds a bridge to a clean energy future. The Company's IRP sets a trajectory to achieve net zero carbon emissions by 2040 for all sources of generation (market, owned, and contracted) used to supply customer demand. The Company's IRP also eliminates more than 63 million tons of carbon emissions and sets a path to exceed the Biden Administration's National Determined Contribution target for the United States under the Paris Climate Agreement and Governor Whitmer's MI Healthy Climate Plan, which both aim to achieve net-zero carbon emissions by 2050. Furthermore, the Company's IRP dramatically reduces emissions from criteria pollutants such as sulfur dioxide (SO2), nitrogen oxides (NOx), mercury, and particulate matter, avoids more than 220 billion gallons of water usage each year, and avoids the production of more than 3 billion cubic yards of coal ash waste.

5. In this proceeding, the Company is specifically seeking approval of a PCA which represents the most reasonable and prudent means of meeting the Company's energy and capacity

needs over the 5, 10, and 15-year time horizons, consistent with MCL 460.6t. With the approval of the Company's PCA, the Company intends to continue filing IRPs every three years. The Company's PCA, which is inclusive of all other proposals presented by the Company in this proceeding, includes:

i. The accelerated retirement of the Company's Karn Units 3 and 4 from May 31, 2031 to May 31, 2023, Campbell Units 1 and 2 from May 31, 2031 to May 31, 2025, and Campbell Unit 3 from December 31, 2039 to May 31, 2025 and the replacement of those resources with the purchase of existing natural gas-fueled resources, in addition to the expansion of the levels of solar and demand-side resources. The purchase of existing gas units will include the purchase of the New Covert Generating Facility ("Covert Plant") on or about May 31, 2023, and the purchase of Dearborn Industrial Generation ("DIG Plant"), the Livingston Generating Station ("Livingston Plant"), and the Kalamazoo River Generating Station ("Kalamazoo Plant") on or about May 31, 2025. The accelerated retirement and purchase of the aforementioned resources are conditioned on the approval of regulatory asset treatment to recover the remaining net book balances of the above identified Campbell and Karn units through their current design lives and a finding that the total purchase costs of the Covert Plant ($815 million) and the DIG, Livingston, and Kalamazoo plants ($530 million) are reasonable and prudent for cost recovery purposes pursuant to MCL 460.6t;

ii. Approval of the acquisition and purchase costs of the Covert, DIG, Kalamazoo, and Livingston plants, in the manner described in the Company's direct testimony and exhibits filed in support of this Application, 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, as reasonable and prudent for cost recovery purposes pursuant to MCL 460.6t;

iii. Certain accounting approvals which include: (i) regulatory asset treatment, with full return, to recover the remaining net book balances of Karn Units 3 and 4 and Campbell Units 1, 2, and 3 through their current design lives; (ii) approval to defer employee retention costs; and (iii) approval to recover retirement transition costs through a regulatory asset;

iv. Requested approval of the selection and proposed purchase of the DIG, Kalamazoo, and Livingston plants by Consumers Energy from its affiliate, CMS Enterprises Company ("CMS Enterprises"). The transaction was a result of a competitive solicitation and is compliant with the Commission's Code of Conduct rules. The competitive solicitation also complied with the Federal Energy Regulatory Commission's ("FERC") standards for determining that an acquisition involving an affiliate will not adversely affect competition and is consistent with the public interest as it satisfied the four principles – Transparency, Definition, Evaluation, and

Oversight – of FERC's solicitation guidelines. 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, Kalamazoo, and Livingston plants from CMS Enterprises;

v. Improvements to the Company's currently approved IRP competitive procurement process used to acquire the new supply-side resources in the Company's PCA which include greater flexibility in the amount of capacity ultimately acquired in each solicitation and greater certainty regarding the Commission approval process for the new resources selected;

vi. The continued use of the competitive procurement process for determining full PURPA avoided cost rates and the Company's capacity needs or sufficiency for the purposes of PURPA. The Company is also requesting certain modifications to its currently approved PURPA avoided cost construct. Furthermore, the Company is requesting a continuation of the Commission's determination that the Company does not have a PURPA capacity need so long as it is implementing the PCA, with the competitive procurement approach proposed by the Company; and

vii. Continued recovery of an FCM and application of that FCM on all new or newly modified PPAs. The Company is also proposing an adjustment to the methodology and level of FCM applied to PPAs, based on the FCM initially approved in Case No. U-20165.

The Company's PCA represents a fully integrated and optimized plan which requires approval in its entirety. The remainder of this Application describes the development of the Company's IRP, provides a high-level overview of the Company's PCA, and presents the Company's requested relief.

II. Development of the IRP and Overview of the PCA

6. The required components of an IRP filing are specifically provided in MCL 460.6t(5)(a)-(o). Furthermore, MCL 460.6t(8) provides that the Commission shall approve a proposed IRP if the Commission determines that the IRP represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs. To make such a determination, the Commission must consider whether the proposed IRP appropriately balances the following factors:

> (i) Resource adequacy and capacity to serve anticipated peak electric load, applicable planning reserve margin, and local clearing requirement.
>
> (ii) Compliance with applicable state and federal environmental regulations.
>
> (iii) Competitive pricing.
>
> (iv) Reliability.
>
> (v) Commodity price risks.
>
> (vi) Diversity of generation supply.
>
> (vii) Whether the proposed levels of peak load reduction and energy waste reduction are reasonable and cost effective. Exceeding the renewable energy resources and energy waste reduction goal in section 1 of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001, by a utility shall not, in and of itself, be grounds for determining that the proposed levels of peak load reduction, renewable energy, and energy waste reduction are not reasonable and cost effective.

7. Pursuant to MCL 460.6t, the Commission was required to: (i) establish modeling scenarios and assumptions each electric utility should include in addition to its own scenarios and assumptions in developing an IRP, and (ii) establish filing requirements, including application forms and instructions, and filing deadlines for an IRP filed by a utility regulated by the Commission. Specifically, MCL 460.6t(1)(f) provides that the Commission shall:

> (f) Establish the modeling scenarios and assumptions each electric utility should include in addition to its own scenarios and assumptions in developing its integrated resource plan filed under subsection (3), including, but not limited to, all of the following:
>
> (i) Any required planning reserve margins and local clearing requirements.
>
> (ii) All applicable state and federal environmental regulations, laws, and rules identified in this subsection.

> (iii) Any supply-side and demand-side resources that reasonably could address any need for additional generation capacity, including, but not limited to, the type of generation technology for any proposed generation facility, projected energy waste reduction savings, and projected load management and demand response savings.
>
> (iv) Any regional infrastructure limitations in this state.
>
> (v) The projected costs of different types of fuel used for electric generation.

Furthermore, MCL 460.6t(3) provides, in relevant part, that:

> The commission shall issue an order establishing filing requirements, including application forms and instructions, and filing deadlines for an integrated resource plan filed by an electric utility whose rates are regulated by the commission.

In compliance with the above statutory provisions, the Commission issued an Order dated November 21, 2017 in Case No. U-18418 approving "Michigan Integrated Resource Planning Parameters." The Commission also issued a December 20, 2017 Order in Case No. U-18461, which approved "Integrated Resource Plan Filing Requirements." Moreover, on February 18, 2021, the Commission issued an Order in Case No. U-20633 directing Consumers Energy to include an additional scenario ("Carbon Reduction Scenario"), inclusive of two carbon sensitivities, in the Company's 2021 IRP filing. These documents set forth all required IRP modeling scenarios and assumptions, requirements, instructions, and guidelines for utilities seeking relief pursuant to MCL 460.6t.

8. The Company's IRP meets the statutory requirements for an IRP filed before the Commission. The Company's testimony and exhibits which accompany this Application address the components required to be included in an IRP, and address the factors which the Commission shall consider in approving an IRP, and establish that the Company's PCA represents "the most reasonable and prudent means of meeting the electric utility's energy and capacity needs." The

Company's filing further explains its planning objectives, which are based on a commitment to *People*, *Planet*, and *Prosperity*, and how these planning objectives align with the factors which must be considered by the Commission.

9. The Company's IRP also meets the Commission's adopted modeling scenarios, assumptions, and filing requirements. The modeling process used by the Company to develop the IRP was rigorous and comprehensive, consistent with good utility practice, followed all applicable Commission rules, and ultimately ensures the identification of the most reasonable and prudent resources to serve customers in a cost-effective and reliable manner. As required by Case No. U-18418, the Company's IRP considered three different scenarios: Business As Usual; Emerging Technology; and Environmental Policy. In addition to these three scenarios, the Company also considered a collection of sensitivities which were required to be evaluated on each of the scenarios. The Company further modeled three additional scenarios that mirrored the mandated scenarios described above, but used the Company's natural gas price forecast instead of the Energy Information Administration natural gas price forecast mandated to be used by the Commission. In addition, the Company modeled an Advanced Technology scenario to gain an understanding of impacts to the resource plan related to aggressive growth of electric vehicle adoption and behind-the-meter generation coupled with a flat-to-declining load forecast with declining costs in batteries and distribution connected solar. The Company also modeled the Carbon Reduction Scenario as required in Case No. U-20633. The Company's modeling in support of its IRP, as described above and in the testimony and exhibits which accompany this Application, was validated by an independent third-party analysis.

10. Consistent with recommendations in the Commission's filing requirements, the Company conducted a series of public outreach events during its IRP modeling efforts which

sought to inform the public regarding the Company's IRP activities and solicit feedback which would be used in the development of the Company's IRP. Public outreach events occurred on August 18, 2020; September 15, 2020; October 13, 2020; and November 10, 2020. Consumers Energy also hosted a series of technical workshops for stakeholder groups expected to be highly involved in the technical aspects of the IRP on December 12, 2019; May 28, 2020; and January 28, 2021. A report detailing the Company's public outreach efforts and the feedback received from the public is provided with the Company's filing as Exhibit A-2 (RTB-2).

11. Subsequent to the completion of the Company's IRP modeling efforts, the Company established a PCA which represents the Company's plan for meeting the energy and capacity needs of customers through 2040. The Company's PCA proposes the accelerated retirement of Karn Units 3 and 4 in the year 2023 (from 2031) and Campbell Units 1, 2, and 3 in 2025 (from 2031 for Campbell Units 1 and 2 and from 2039 for Campbell Unit 3) and backfilling the capacity lost by the retirement of those resources with the acquisition of the Covert Plant (2023) and the DIG, Kalamazoo, and Livingston plants (2025). The Company also intends to continue the expansion of solar, batteries, and demand-side management programs, in a manner similar to the Company's 2018 IRP, to meet future capacity needs and increase resource diversity. In the later portion of the 20-year outlook, the PCA relies on EWR, CVR, DR, solar, and battery resources to backfill the capacity lost by a large PPA set to expire in 2030. The investments and other relief sought for approval as part of the Company's PCA are included in this filing and addressed in more detail below.

12. The Company's PCA embodies a truly balanced plan across the Company's *People*, *Planet*, and *Prosperity* planning objectives and the Commission's planning objectives. It offers continued growth of clean renewable resources, at or better than the levels identified in the

approved 2018 IRP; greater electric supply reliability; greater customer savings realized in the short and mid-term periods of the PCA; near-term planet benefits due to reduction in carbon emissions, other air emissions, water, and waste; and financial stability of the regulated electric utility. The Company is committed to achieving net zero carbon emissions by 2040 for all generating resources to meet customers' needs and is well positioned to achieve this goal by continuing the efforts to support research and development, technology solutions to enhance operational flexibility of a dynamic electric system created by intermittent resources and demand-side management programs, and gaining learnings from the development of the solar glidepath identified in the PCA. Additionally, future learning opportunities pursued by the Company will help to accelerate the pace of the clean energy transformation with a mix of technology solutions.

13. The Company's PCA was evaluated with a complex and robust risk assessment methodology. The Company's risk assessment methodology, which is consistent with the risk assessment methodology mandated by the Commission in Case No. U-18461, used a five-step process to assess the levels of risk related to selecting a resource portfolio. These steps included: (i) portfolio optimization reviews; (ii) a net present value review of portfolio optimizations; (iii) an evaluation of all optimized portfolios in all scenarios; (iv) stochastic risk analysis; and (v) deterministic risk analysis. The risk assessment performed in this IRP supports the PCA as the best plan for Michigan. The PCA provides a resource portfolio that: (i) is robust enough to serve Consumers Energy's full-service electric customer demand all hours, 365 days per year; (ii) stands up to potential significant increases in electric demand; (iii) delivers on generation diversity; and (iv) provides less financial risk to customers. The robust nature of the Company's analysis

conducted for this IRP further establishes that the PCA represents the most reasonable and prudent plan to meet the energy and capacity needs of the Company's customers.

14. As indicated above, as part of the settlement agreement approved by the Commission in Case No. U-20165, the Company was required to perform an accelerated retirement analysis of Campbell Units 1 and 2 which specifically examined the potential retirement of those units in isolation and together, in years 2024, 2025, 2026, and 2028, as well as the continued operation of the units through their end-of-design lives in 2031. The accelerated retirement of Campbell Unit 3 was included in the analysis after leading indicators in the Campbell Units 1 and 2 results identified potential solutions to exit coal generation while continuing to serve customers reliably. Additionally, the Company examined the accelerated retirement of Karn Units 3 and 4 as early as 2023 and no later than 2025. Based on the results of the economic analysis in combination with the electric supply reliability, customer rate impact, environmental impact, employee and community impact, and financial impact assessments, the Company is proposing to retire Karn Units 3 and 4 in 2023, with the already approved retirement of Karn Units 1 and 2 in 2023, and Campbell Units 1, 2, and 3 in 2025.

15. Because the PCA recommends the retirement of Karn Units 3 and 4 in 2023 and Campbell Units 1, 2, and 3 in 2025, which is before the end of the design lives for those units, and before the remaining book balance would be recovered through traditional depreciation rates, the Company is requesting approval to recover the remaining net book value and decommissioning costs of those units through regulatory asset treatment, with full return.

16. The settlement agreement approved in Case No. U-20165 provides for a competitive bidding process to address future capacity needs of the Company. In this case, the Company is proposing the continuation of that competitive procurement process, with certain

modifications, for the procurement of the supply-side capacity resources identified in the PCA. The Company is also proposing to continue using the competitive procurement process for determining PURPA avoided cost rates, as well as determining whether the Company has a capacity need or sufficiency for purposes of PURPA. Although the current manner in which the Company's PURPA avoided cost rates and PURPA capacity position are determined is proposed to continue, the Company is proposing certain modifications to the Company's currently approved PURPA avoided cost construct. Furthermore, since the Company is proposing to continue the competitive procurement of the supply-side capacity resources identified in the PCA, the Company is also seeking to continue the recovery of an FCM with certain adjustments.

17. The Company's PCA is a fully integrated proposal that ties the planned evolution of the Company's resource portfolio through 2040 to the numerous proposals described above, and in the testimony and exhibits filed in this proceeding. Since the Company's PCA is a fully integrated proposal with numerous interdependent components, modification to, or rejection of, a proposal made in the PCA impacts the PCA's viability and the Company's willingness to execute on the remaining portions of the PCA not modified or rejected. As such, the Company reserves the right to abandon or amend its PCA if the Commission rejects or modifies any of the Company's proposals presented in this IRP.

18. An IRP report which, among other things, details the Company's existing electric generating fleet and PPAs, resource adequacy through 2040, and analysis and decisions in selecting the PCA and proposed resource acquisition strategy are provided with this filing as Exhibit A-2 (RTB-2).

III. Cost Approvals

19. MCL 460.6t(11) provides that, in approving an IRP, the Commission shall specify the approved costs for future recovery as follows:

> In approving an integrated resource plan under this section, the commission shall specify the costs approved for the construction of or significant investment in an electric generation facility, the purchase of an existing electric generation facility, the purchase of power under the terms of the power purchase agreement, or other investments or resources used to meet energy and capacity needs that are included in the approved integrated resource plan. The costs for specifically identified investments, including the costs for facilities under subsection (12), included in an approved integrated resource plan that are commenced within 3 years after the commission's order approving the initial plan, amended plan, or plan review are considered reasonable and prudent for cost recovery purposes.

20. Consistent with MCL 460.6t(11), the Company is requesting approval of the acquisition and purchase costs of the Covert, DIG, Kalamazoo, and Livingston plants, in the manner described in the Company's direct testimony and exhibits filed in support of this Application, and costs related to EWR, DR, and CVR which will be commenced within three years of the Commission's expected approval of the Company's IRP. Since a final order is required to be issued no later than 360 days after an electric utility files an IRP, the Company has used June 2022 through June 2025 as the three-year cost recovery approval period in this case. See MCL 460.6t(7).

21. As is explained in more detail in the Company's direct testimony and exhibits which accompany this filing, the Company is proposing to purchase the Covert Plant on or about May 31, 2023 and the DIG, Kalamazoo, and Livingston plants on or about May 31, 2025. The Company is requesting Commission approval of the acquisition and purchase costs of $815 million for the Covert Plant and $530 million for the DIG, Kalamazoo, and Livingston plants as reasonable

and prudent for cost recovery purposes pursuant to MCL 460.6t. In addition to the costs to purchase the plants, the Company's direct testimony and exhibits filed in support of this Application detail the projected costs to operate the plants, commodity sales contracts attributable to the DIG, Kalamazoo, and Livingston plants, which the Company will assume after the acquisition of the plants, and the proposed treatment of the revenues received by the Company through the commodity sales contracts.

22. The Company is requesting cost recovery of the following: (i) DR costs for January 1, 2023 to June 30, 2025 ($23,751,000 capital, $3,100,000 Operating and Maintenance ("O&M"), $26,300,000 of incentive, to achieve a total of 641 MW (657 Zonal Resource Credits ("ZRCs")) in 2025); (ii) EWR costs for January 1, 2024 to June 30, 2025 ($226,721,558 O&M, $45,344,312 of incentive, 545,305 MWh savings, 879 MW savings); and (iii) CVR costs for January 1, 2023 to June 30, 2025 ($11,812,010 capital, $1,389,066 O&M, 295,983 MWh savings, 26.65 MW (27.5 ZRCs) savings). The Company requests a finding that these DR, EWR, and CVR costs are reasonable and prudent for cost recovery purposes pursuant to MCL 460.6t.

IV. Requested Accounting and Other Approvals

23. As explained above, the Company's proposal to retire Karn Units 3 and 4 in 2023 and Campbell Units 1, 2, and 3 in 2025 is contingent on the Commission's approval of the recovery of the unrecovered book balances of these units and the approval of the costs to purchase the Covert, DIG, Kalamazoo, and Livingston plants. The Company is requesting approval to recover the remaining net book balances and decommissioning costs of Karn Units 3 and 4 and Campbell Units 1, 2, and 3 through regulatory asset treatment, with full return. The Company's proposal to recover the remaining net book balances of the to-be-retired units over their remaining design lives

is a balanced proposal that would preserve the Company's credit and financial profile and is a requirement for the Company to proceed with the PCA.

24. With respect to the recovery of the remaining net book balances, the Company is specifically proposing to continue to depreciate Karn Units 3 and 4 and Campbell Units 1, 2, and 3 at the current Commission-approved depreciation rates until base rates are reset in the next electric general rate case. In the next rate case filed after the conclusion of this IRP proceeding, the actual remaining net book balance would be removed from plant-in-service and accumulated depreciation accounts and placed into a regulatory asset. The Company proposes to set an annual amortization rate that allows for the recovery of the remaining net book value and the decommissioning costs by 2031 for costs associated with Karn Units 3 and 4 and Campbell Units 1 and 2 and by 2040 for costs associated with Campbell Unit 3 (i.e., consistent with the design lives of each unit).

25. In addition to the above, the Company is also requesting certain other accounting approvals related to the proposed retirement of Karn Units 3 and 4 and Campbell Units 1, 2, and 3. These requested accounting approvals include: (i) approval to defer employee retention costs, and (ii) approval to make retirement transition costs a regulatory asset.

26. Since the DIG, Kalamazoo, and Livingston plants are owned by subsidiaries of the Company's affiliate CMS Enterprises, the Company requests approval of the selection and proposed purchase of the plants. The transaction was the result of a competitive solicitation and is compliant with the Commission's Code of Conduct rules. The competitive solicitation also complied with FERC standards for determining that an acquisition involving an affiliate will not adversely affect competition and is consistent with the public interest as it satisfied the four principles – Transparency, Definition, Evaluation, and Oversight – of FERC's solicitation

guidelines. The purchase price for the Company's acquisition of the DIG, Kalamazoo, and Livingston plants from CMS Enterprises reflects a fair market price for the assets and is lower than the Company's cost of capacity. The transaction was part of the Company's 2021 existing gas plant competitive solicitation that was independently administered by a Request for Proposal ("RFP") manager. The use of an RFP manager allowed for an independent, fair, and transparent solicitation. It is under this process that a bid which included the DIG, Kalamazoo, and Livingston plants was selected as an economical and fair market bid. Since the contract price is lower than the Company's costs, the Company's selection and proposed purchase of the plants complies with the Commission's Code of Conduct.

27. Alternatively, 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, Kalamazoo, and Livingston plants. Such a waiver would be appropriate because the purchase agreement for the acquisition of the DIG, Kalamazoo, and Livingston plants was made pursuant to a market-based competitive solicitation conducted by an independent third party. The contract between the Company and its affiliate resulted from an arms-length transaction. There was no preferential treatment afforded to the Company's affiliate. Customers benefit from the participation of the Company's affiliate in the competitive solicitation, and the potential harm, which the Code of Conduct was intended to prevent, is not present.

V. Competitive Procurement

28. As set forth above, in this case, the Company is proposing a continuation of the competitive procurement process approved in Case No. U-20165, with certain modifications, for the procurement of the supply-side capacity resources identified in the PCA. The Company is seeking approval of a modified competitive procurement approach which includes improvements

primarily based upon learnings from the two competitive solicitations issued in years 2019 and 2020. These improvements include greater flexibility in the amount of capacity ultimately acquired in each solicitation and greater certainty regarding the Commission approval process for the new resources selected.

29. Among other things, the Company proposes to acquire at least 50% of the new capacity acquired through the competitive solicitation process from Company-owned resources with the remaining new capacity coming from either PPAs or Company-owned resources, depending on economics. The Company also proposes to acquire more or less than the targeted MWs, as identified in the PCA, in each annual solicitation to better obtain the best projects for customers. Given the flexibility in the MW acquired in each solicitation, the Company proposes to reconcile the ownership structure and procured MWs, against the MWs needed to implement the PCA, in future IRP proceedings. Furthermore, the Company is proposing additional flexibility on the commercial operation dates for resources acquired in annual competitive solicitations and adjustments to the term length of solicited PPAs so that greater value can be provided to customers. In addition, the Company's proposal clarifies that, although the Company will use the competitive solicitation process to acquire the resources in the PCA, the Company intends to pursue supply-side resource pilots outside of the competitive solicitation process to better understand how emerging technologies fit within the Company's resource portfolio and how those emerging technologies may be better considered in future IRPs. The Company's proposed competitive bidding improvements are further detailed in the direct testimony filed in support of this Application.

VI. <u>Avoided Costs</u>

30. In its October 5, 2018 Order in Case No. U-20165, the Commission found it appropriate to determine PURPA avoided costs in the context of IRP proceedings. Specifically, the Commission found "that Section 6t requires a comprehensive, holistic examination of resource planning and costs, and that examination cannot exclude PURPA." MPSC Case No. U-20165, October 5, 2018 Order, page 17. In that matter, the Commission ultimately approved a settlement agreement which provided for the Company's competitive solicitation process to determine the Company's PURPA avoided cost rates. That settlement agreement also permitted the use of a five-year outlook for determining capacity needs and established that the Company does not have a PURPA capacity need if the Company is implementing the competitive bidding process used to acquire the resources in its PCA. In its October 29, 2020 Order in Case No. U-20905 *et al.*, the Commission has made clear that it intends to consider the Company's PURPA avoided costs in the context of this IRP proceeding. See MPSC Case No. U-20905 *et al.*, October 29, 2020 Order, page 14.

31. Since the Company is proposing the continued use of the competitive procurement process for the acquisition of new supply-side capacity, the Company is also proposing to continue using the competitive procurement process for determining PURPA avoided cost rates, as well as determining whether the Company has a capacity need or sufficiency for purposes of PURPA. Although the current manner in which the Company's PURPA avoided cost rates and PURPA capacity is proposed to continue, the Company is proposing certain modifications to the Company's currently approved PURPA avoided cost construct. Among other things, the Company is proposing modifications to the eligibility for certain avoided cost rates, the eligibility for the standard offer contract and tariff, and the maximum term lengths for PPAs entered as a result of

the Company's obligations under PURPA. The Company's proposed modifications are detailed in the direct testimony filed in support of this Application.

32. The Company is further requesting: (i) a continued finding from the Commission that the Company does not have a PURPA capacity need so long as the Company is implementing the PCA, with the competitive procurement approach proposed by the Company; and (ii) clarification that the required review of the Company's PURPA avoided cost construct is adequately met through the IRP filings that the Company has agreed to file every three years, as opposed to a biennial basis.

VII. PPA FCM

33. MCL 460.6t(15) provides that:

> For power purchase agreements that a utility enters into after the effective date of the amendatory act that added this section with an entity that is not affiliated with that utility, the commission shall consider and may authorize a financial incentive for that utility that does not exceed the utility's weighted average cost of capital.

In accordance with MCL 460.6t(15), the settlement agreement approved in Case No. U-20165 provided for an FCM on PPAs approved by the Commission on or after January 1, 2019, excluding Renewable Energy Plan PPAs. Since the Company is proposing to continue the competitive procurement of the supply-side capacity resources identified in the PCA, the Company is also seeking to continue to apply and recover an FCM on all new or newly modified PPAs. However, the Company is proposing to remove the cap on the FCM and apply the FCM to all future PPAs and PPA amendments. The Company is also proposing an adjustment to the methodology and level of FCM applied to PPAs, based on the FCM initially approved in Case No. U-20165. The Company's FCM modifications are further detailed in the direct testimony filed in support of this Application.

VIII. Testimony and Exhibits and Other Matters

34. Consumers Energy is, concurrently with this Application, filing written testimony and exhibits in support of its IRP and other relief Consumers Energy is seeking in this case. Reference to this material will provide additional details on the relief being sought. The relief described in the testimony and exhibits should be considered as if specifically requested in this Application. Consumers Energy expressly reserves the right to revise, amend, or otherwise change the relief it is requesting in any way appropriate depending upon the duration and progress of hearings in this proceeding, the issuance of Orders that have an impact upon this case, or the occurrence of other material events. Consumers Energy also specifically reserves the right, pursuant to MCL 460.6t(7), to update the cost estimates within 150 days of the filing of this Application.

35. In addition to the issues described above, it is possible that other pending or to-be-filed proceedings or other events may have impacts upon the Company's requests in this proceeding. These impacts will be evaluated for materiality and may need to be considered in the results of this proceeding.

36. All proposals made by the Company in this IRP are integrally part of the Company's PCA. Since the Company's PCA is a fully integrated proposal with numerous interdependent components, modification to or rejection of a proposal made in the PCA impacts the PCA's viability and the Company's willingness to execute on the remaining portions of the PCA not modified or rejected. As such, the Company reserves the right to abandon or amend its PCA if the Commission rejects or modifies any of the Company's proposals presented in this IRP.

37. As required in the Commission's IRP filing requirements approved in Case No. U-18461, the Company has included a Letter of Transmittal as Attachment A to this Application.

The Company's Letter of Transmittal expresses a commitment to the Company's preferred resource plan and resource acquisition strategy, and has been signed by an officer of the Company who has authority to commit the Company to the resource acquisition strategy acknowledging that the Company reserves the right to make changes to its resource acquisition strategies as appropriate due to changing circumstances.

38. Furthermore, due to the confidential nature of information contained in and included with the Company's IRP filing, the Company is proposing entry of a protective order. The Company's proposed protective order is included as Attachment B to this Application. The Company requests that the entry of its proposed protective order be considered during the prehearing conference for this matter.

IV. Request for Relief

WHEREFORE, Consumers Energy Company requests that the Michigan Public Service Commission:

A. Approve Consumers Energy Company's Integrated Resource Plan by approving the Proposed Course of Action, which is inclusive of all proposals presented by Consumers Energy Company in this case, as the most reasonable and prudent means of meeting Consumers Energy Company's energy and capacity needs;

B. Approve Consumers Energy Company's acquisition and proposed purchase costs for the New Covert Generating Facility, Dearborn Industrial Generation, the Kalamazoo River Generating Station, and the Livingston Generating Station, in the manner described in Consumers Energy Company's direct testimony and exhibits filed in support of this Application, and proposed Energy Waste Reduction, Demand Response, and Conservation Voltage Reduction costs which will be commenced by Consumers Energy Company within three years following the Michigan

Public Service Commission's expected approval of Consumers Energy Company's Integrated Resource Plan as reasonable and prudent for cost recovery purposes pursuant to MCL 460.6t;

C. Approval of the selection and proposed purchase of Dearborn Industrial Generation, the Kalamazoo River Generating Station, and the Livingston Generating Station, by Consumers Energy Company from its affiliate, CMS Enterprises Company. The transaction was a result of a competitive solicitation and is compliant with the Michigan Public Service Commission's Code of Conduct requirements. The competitive solicitation also complied with the Federal Energy Regulatory Commission's standards for determining that an acquisition involving an affiliate will not adversely affect competition and is consistent with the public interest as it satisfied the four principles – Transparency, Definition, Evaluation, and Oversight – of Federal Energy Regulatory Commission's solicitation guidelines. In the alternative, while complying with all other provisions of the Code of Conduct, Consumers Energy 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 Dearborn Industrial Generation, the Kalamazoo River Generating Station, and the Livingston Generating Station, from CMS Enterprises Company;

D. Approve Consumers Energy Company's proposal to recover the unrecovered book balances of D.E. Karn Units 3 and 4 and J.H. Campbell Units 1, 2, and 3, including decommissioning costs, through regulatory asset treatment, with full return, over the design lives of those units;

E. Approve Consumers Energy Company's proposals to: (i) defer employee retention costs related to the proposed accelerated retirements of D.E. Karn Units 3 and 4 and J.H. Campbell Units 1, 2, and 3; and (ii) recover retirement transition costs through a regulatory asset.

F. Approve Consumers Energy Company's proposed competitive procurement process and the use of that competitive procurement process for: (i) determining avoided costs rates and (ii) determining and addressing the Company's capacity position pursuant to the Public Utility Regulatory Policies Act of 1978;

G. Determine that the Company has no Public Utility Regulatory Policies Act of 1978 capacity need so long as the Company is implementing the Proposed Course of Action, with the competitive procurement process proposed by the Company;

H. Approve Consumers Energy Company's proposed Financial Compensation Mechanism for any new, or newly amended, Power Purchase Agreements entered by the Company; and

I. Grant Consumers Energy Company such other and further relief as is just and reasonable.

Respectfully submitted,

CONSUMERS ENERGY COMPANY

Dated: June 30, 2021

By: ______________________________
Timothy J. Sparks
Vice President of Electric Grid Integration
Consumers Energy Company

____
Robert W. Beach (P73112)
Bret A. Totoraitis (P72654)
Anne M. Uitvlugt (P71641)
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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 Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))))	Case No. U-21090

VERIFICATION

Timothy J. Sparks, being first duly sworn, deposes and says that he is the Vice President of Electric Grid Integration of Consumers Energy Company; that he has executed the foregoing Application for, and on behalf of, Consumers Energy Company; that he has read the foregoing Application and is familiar with the contents thereof; that the facts contained therein are true, to the best of his knowledge and belief; and that he is duly authorized to execute such Application on behalf of Consumers Energy Company.

Dated: June 30, 2021

Timothy J. Sparks
Vice President of Electric Grid Integration
Consumers Energy Company

ATTACHMENT 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

LETTER OF TRANSMITTAL

I, Timothy J. Sparks, hereby express Consumers Energy Company's commitment to the Company's Integrated Resource Plan Proposed Course of Action, which represents the Company's preferred resource plan and resource acquisition strategy, and hereby sign this Letter of Transmittal as an officer of the Company having the authority to commit the Company to the resource acquisition strategy, acknowledging that the Company reserves the right to make changes to its resource acquisition strategies as appropriate due to changing circumstances.

Dated: June 30, 2021

Timothy J. Sparks
Vice President of Electric Grid Integration
Consumers Energy Company

ATTACHMENT B

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

PROTECTIVE ORDER

This Protective Order governs the use and disposition of Protected Material that Consumers Energy Company ("Applicant") or any other Party discloses to another Party during the course of this proceeding. The Applicant or other Party disclosing Protected Material is referred to as the "Disclosing Party"; the recipient is the "Receiving Party" (defined further below). The intent of this Protective Order is to protect non-public, confidential information and materials so designated by the Applicant or by any other party, which information and materials contain confidential, proprietary, or commercially sensitive information. This Protective Order defines "Protected Material" and describes the manner in which Protected Material is to be identified and treated. Accordingly, it is ordered:

I. "Protected Material" and Other Definitions

A. For the purposes of this Protective Order, "Protected Material" consists of trade secrets or confidential, proprietary, or commercially sensitive information provided in Disclosing Party's discovery or audit responses, any witness' related exhibit and testimony, and any arguments of counsel describing or relying upon the Protected Material. Subject to challenge under Paragraph IV.A, Protected Material shall consist of non-public confidential information and materials including, but not limited to, the following information disclosed during the course of this case if it is marked as required by this Protective Order:

1. Trade secrets or confidential, proprietary, or commercially sensitive information provided in response to discovery, in response to an order issued by the presiding hearing officer or the Michigan Public Service Commission ("MPSC" or the "Commission"), in testimony or exhibits filed later in this case, or in arguments of counsel;

2. To the extent permitted, information obtained under license from a third-party licensor, to which the Disclosing Party or witnesses engaged by the Disclosing Party is a licensee, that is subject to any confidentiality or non-transferability clause. This information includes reports; analyses; models (including related inputs and outputs); trade secrets; and confidential, proprietary, or commercially sensitive information that the Disclosing Party or one of its witnesses receives as a licensee and is authorized by the third- party licensor to disclose consistent with the terms and conditions of this Protective Order; and

3. Information that could identify the bidders and bids, including the winning bid, in a competitive solicitation for a power purchase agreement or in a competitively bid engineering, procurement, or construction contract at any stage of the selection process (*i.e.*, before the Disclosing Party has entered into a power purchase agreement or selected a contractor).

B. The information subject to this Protective Order does not include:

1. Information that is or has become available to the public through no fault of the Receiving Party or Reviewing Representative and no breach of this Protective Order, or information that is otherwise lawfully known by the Receiving Party without any obligation to hold it in confidence;

2. Information received from a third party free to disclose the information without restriction;

3. Information that is approved for release by written authorization of the Disclosing Party, but only to the extent of the authorization;

4. Information that is required by law or regulation to be disclosed, but only to the extent of the required disclosure; or

5. Information that is disclosed in response to a valid, non-appealable order of a court of competent jurisdiction or governmental body, but only to the extent the order requires.

C. "Party" refers to the Applicant, MPSC Staff ("Staff"), Michigan Attorney General, or any other person, company, organization, or association that is granted intervention in Case No. U-21090 under the Commission's Rules of Practice and Procedure, Mich Admin Code, R 792.10401 et al.

D. "Receiving Party" means any Party to this proceeding who requests or receives access to Protected Material, subject to the requirement that each Reviewing Representative sign a Nondisclosure Certificate attached to this Protective Order as Attachment 1.

E. "Reviewing Representative" means a person who has signed a Nondisclosure Certificate and who is:

1. An attorney who has entered an appearance in this proceeding for a Receiving Party;

2. An attorney, paralegal, or other employee associated, for the purpose of this case, with an attorney described in Paragraph I.E.1;

3. An expert or employee of an expert retained by a Receiving Party to advise, prepare for, or testify in this proceeding; or

4. An employee or other representative of a Receiving Party with significant responsibility in this case.

A Reviewing Representative is responsible for assuring that persons under his or her supervision and control comply with this Protective Order.

F. "Nondisclosure Certificate" means the certificate attached to this Protective Order as Attachment 1, which is signed by a Reviewing Representative who has been granted access to Protected Material and agreed to be bound by the terms of this Protective Order.

II. <u>Access to and Use of Protected Material</u>

A. This Protective Order governs the use of all Protected Material that is marked as required by Paragraph III.A and made available for review by the Disclosing Party to any

Receiving Party or Reviewing Representative. This Protective Order protects: (i) the Protected Material; (ii) any copy or reproduction of the Protected Material made by any person; and (iii) any memorandum, handwritten notes, or any other form of information that copies, contains, or discloses Protected Material. All Protected Material in the possession of a Receiving Party shall be maintained in a secure place. Access to Protected Material shall be limited to persons authorized to have access subject to the provisions of this Protective Order.

B. Protected Material shall be used and disclosed by the Receiving Party solely in accordance with the terms and conditions of this Protective Order. A Receiving Party may authorize access to, and use of, Protected Material by a Reviewing Representative identified by the Receiving Party, subject to Paragraphs III and V below, only as necessary to analyze the Protected Material; make or respond to discovery; present evidence; prepare testimony, argument, briefs, or other filings; prepare for cross-examination; consider strategy; and evaluate settlement. These individuals shall not release or disclose the content of Protected Material to any other person or use the information for any other purpose.

C. The Disclosing Party retains the right to object to any designated Reviewing Representative if the Disclosing Party has reason to believe that there is an unacceptable risk of misuse of confidential information. If a Disclosing Party objects to a Reviewing Representative, the Disclosing Party and the Receiving Party will attempt to reach an agreement to accommodate that Receiving Party’s request to review Protected Material. If no agreement is reached, then either the Disclosing Party or the Receiving Party may submit the dispute to the presiding hearing officer. If the Disclosing Party notifies a Receiving Party of an objection to a Reviewing Representative, then the Protected Material shall not be provided to that Reviewing Representative until the objection is resolved by agreement or by the presiding hearing officer.

D. Before reviewing any Protected Material, including copies, reproductions, and copies of notes of Protected Material, a Receiving Party and Reviewing Representative shall sign a copy of the Nondisclosure Certificate (Attachment 1 to this Protective Order) agreeing to be bound by the terms of this Protective Order. The Reviewing Representative shall also provide a copy of the executed Nondisclosure Certificate to the Disclosing Party.

E. Even if no longer engaged in this proceeding, every person who has signed a Nondisclosure Certificate continues to be bound by the provisions of this Protective Order. The obligations under this Protective Order are not extinguished or nullified by entry of a final order in this case and are enforceable by the MPSC or a court of competent jurisdiction. To the extent Protected Material is not returned to a Disclosing Party, it remains subject to this Protective Order.

F. Members of the Commission, Commission staff assigned to assist the Commission with its deliberations, and the presiding hearing officer shall have access to all Protected Material that is submitted to the Commission under seal without the need to sign the Nondisclosure Certificate.

G. A Party retains the right to seek further restrictions on the dissemination of Protected Material to persons who have or may subsequently seek to intervene in this MPSC proceeding.

H. Nothing in this Protective Order precludes a Party from asserting a timely evidentiary objection to the proposed admission of Protected Material into the evidentiary record for this case.

III. Procedures

A. The Disclosing Party shall mark any information that it considers confidential as "CONFIDENTIAL: SUBJECT TO THE PROTECTIVE ORDER ISSUED IN CASE NO. U-21090." If the Receiving Party or a Reviewing Representative makes copies of any Protected Material, they shall conspicuously mark the copies as Protected Material. Notes of Protected Material shall also be conspicuously marked as Protected Material by the person making the notes.

B. If a Receiving Party wants to quote, refer to, or otherwise use Protected Material in pleadings, pre-filed testimony, exhibits, cross-examination, briefs, oral argument, comments, or in some other form in this proceeding (including administrative or judicial appeals), the Receiving Party shall do so consistent with procedures that will maintain the confidentiality of the Protected Material. For purposes of this Protective Order, the following procedures apply:

1. Written submissions using Protected Material shall be filed in a sealed record to be maintained by the MPSC's Docket Section, or by a court of competent jurisdiction, in envelopes clearly marked on the outside, "CONFIDENTIAL – SUBJECT TO THE PROTECTIVE ORDER ISSUED IN CASE NO. U-21090." Simultaneously, identical documents and materials, with the Protected Material redacted, shall be filed and disclosed the same way that evidence or briefs are usually filed;

2. Oral testimony, examination of witnesses, or argument about Protected Material shall be conducted on a separate record to be maintained by the MPSC's Docket Section or by a court of competent jurisdiction. These separate record proceedings shall be closed to all persons except those furnishing the Protected Material and persons otherwise subject to this Protective Order. The Receiving Party presenting the Protected Material during the course of the proceeding shall give the presiding officer or court sufficient notice to allow the presiding officer or court an opportunity to take measures to protect the confidentiality of the Protected Material; and

3. Copies of the documents filed with the MPSC or a court of competent jurisdiction, which contain Protected Material, including the portions of the exhibits, transcripts, or briefs that refer to Protected Material, must be sealed

and maintained in the MPSC's or court's files with a copy of the Protective Order attached.

C. It is intended that the Protected Material subject to this Protective Order should be shielded from disclosure by a Receiving Party. If any person files a request under the Freedom of Information Act with a governmental agency participating in this proceeding, including, but not limited to, the MPSC, the MPSC Staff, and the Michigan Attorney General, seeking access to documents subject to this Protective Order, the governmental agency shall immediately notify the Disclosing Party, and the Disclosing Party may take whatever legal actions it deems appropriate to protect the Protected Material from disclosure. In light of Section 5 of the Freedom of Information Act, MCL 15.235, the notice must be given at least five (5) business days before the governmental agency grants the request in full or in part.

IV. Termination of Protected Status

A. A Receiving Party reserves the right to challenge whether a document or information is Protected Material and whether this information can be withheld under this Protective Order. In response to a motion, the Commission or the presiding hearing officer in this case may revoke a document's protected status after notice and hearing. If the presiding hearing officer revokes a document's protected status, then the document loses its protected status after 14 days unless a Party files an application for leave to appeal the ruling to the Commission within that time period. Any Party opposing the application for leave to appeal shall file an answer with the Commission no more than 14 days after the filing and service of the appeal. If an application is filed, then the information will continue to be protected from disclosure until either the time for appeal of the Commission's final order resolving the issue has expired under MCL 462.26 or, if the order is appealed, until judicial review is completed and the time to take further appeals has expired.

B. If a document's protected status is challenged under Paragraph IV.A, the Receiving Party challenging the protected status of the document shall explicitly state its reason for challenging the confidential designation. The Disclosing Party bears the burden of proving that the document should continue to be protected from disclosure.

V. Retention of Documents

A. Protected Material remains the property of the Disclosing Party and only remains available to the Receiving Party until the time expires for petitions for rehearing of a final MPSC order in Case No. U-21090 or until the MPSC has ruled on all petitions for rehearing in this case (if any). However, an attorney for a Receiving Party who has signed a Nondisclosure Certificate and who is representing the Receiving Party in an appeal from an MPSC final order in this case may retain copies of Protected Material until either the time for appeal of the Commission's final order resolving the issue has expired under MCL 462.26 or, if the order is appealed, until judicial review is completed and the time to take further appeals has expired. On or before the time specified by the preceding sentences, the Receiving Party shall return to the Disclosing Party all Protected Material in its possession or in the possession of its Reviewing Representatives-including all copies and notes of Protected Material-or certify in writing to the Disclosing Party that the Protected Material has been destroyed.

B. Notwithstanding the preceding paragraph, Counsel for a Receiving Party may maintain a single confidential file of Protected Material beyond the resolution of this proceeding, provided that this Order will continue in effect with respect to the Protected Material for so long as it is retained by counsel for any requesting Party. If the Protected Material is relevant or reasonably calculated to lead to admissible evidence in another Commission proceeding, then it may be used in such a proceeding subject to the issuance of a new Protective Order in that proceeding. The terms of this Paragraph shall apply until the resolution of Consumers Energy Company's next Integrated Resource Planning case under MCL 460.6t conducted after the conclusion of this case. For purposes of this paragraph, the "resolution" of a case means the expiration of the period of judicial review of a final order of the Commission. Counsel for a Requesting Party may also retain, without time limitation, a single unredacted copy of any of Counsel's own briefs (not including any confidential attachments) that contain information derived from Protected Material, subject to continued confidential treatment in accordance with all obligations of this Protective Order.

VI. <u>Limitations and Disclosures</u>

The provisions of this Protective Order do not apply to a particular document, or portion of a document, described in Paragraph II.A if a Receiving Party can demonstrate that it has been previously disclosed by the Disclosing Party on a non-confidential basis or meets the criteria set forth in Paragraphs I.B.1 through I.B.5. A Receiving Party intending to disclose information taken directly from materials identified as Protected Material must-before actually disclosing the information-do one of the following: (i) contact the Disclosing Party's counsel of record and obtain written permission to disclose the information, or (ii) challenge the confidential nature of the Protected Material and obtain a ruling under Paragraph IV that the information is not confidential and may be disclosed in or on the public record.

VII. <u>Remedies</u>

If a Receiving Party violates this Protective Order by improperly disclosing or using Protected Material, the Receiving Party shall take all necessary steps to remedy the improper disclosure or use. This includes immediately notifying the MPSC, the presiding hearing officer, and the Disclosing Party, in writing, of the identity of the person known or reasonably suspected to have obtained the Protected Material. A Party or person that violates this Protective Order remains subject to this paragraph regardless of whether the Disclosing Party could have discovered the violation earlier than it was discovered. This paragraph applies to both inadvertent and intentional violations. Nothing in this Protective Order limits the Disclosing Party's rights and remedies, at law or in equity, against a Party or person using Protected Material in a manner not authorized by this Protective Order, including the right to obtain injunctive relief in a court of competent jurisdiction to prevent violations of this Protective Order.

____

Administrative Law Judge

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 Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief. ______________________________________	))))))	Case No. U-21090

<u>NONDISCLOSURE CERTIFICATE</u>

By signing this Nondisclosure Certificate, I acknowledge that access to Protected Material is provided to me under the terms and restrictions of the Protective Order issued in Case No. U-21090, that I have been given a copy of and have read the Protective Order, and that I agree to be bound by the terms of the Protective Order. I understand that the substance of the Protected Material (as defined in the Protective Order), any notes from Protected Material, or any other form of information that copies or discloses Protected Material, shall be maintained as confidential and shall not be disclosed to anyone other than in accordance with the Protective Order.

Reviewing Representative

Date:____________________ ______________________________________

Title:
Representing:

____

Printed Name

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 Approval of an Integrated Resource Plan	)	Case No. U-21090
under MCL 460.6t, certain accounting	)	
approvals, and for other relief.	)	
____	)	

DIRECT TESTIMONY

OF

RICHARD T. BLUMENSTOCK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

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 Planning. 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 my current position as Executive Director of Electric Planning.

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

A. My responsibilities as Executive Director of Electric Planning include oversight of all activities associated with planning for the Company's low voltage electric distribution networks, high voltage electric distribution networks, electric generation, energy and capacity supply, and system protection.

Q. What is your formal education 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 testified 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 ("CON") 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 ("REP") 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 ("Palisades") Power Purchase Agreement ("PPA");

- 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; and

- 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.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to provide: (i) an overview of the Company's IRP; (ii) a summary of the objectives and principles of the IRP; (iii) an overview of the study process used to complete the IRP; (iv) a description of the baseline capacity position of the IRP; (v) a summary of the Proposed Course of Action ("PCA") represented as the Company's new Clean Energy Plan; and (vi) a description of the Company's significant proposals and a summary of all requested relief.

Q. Are you sponsoring exhibits with your direct testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-1 (RTB-1)	IRP Filing Requirements Checklist;
Exhibit A-2 (RTB-2)	Consumers Energy IRP Report; and
Exhibit A-3 (RTB-3)	Independent Third-Party Review Report.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

Q. Please explain what the Company is seeking approval for in this IRP?

A. In June 2019, the Commission approved a settlement agreement which resolved the Company's 2018 IRP and resulted in the approval of a PCA which represented the best plan for Michigan at that time. That PCA became the foundation of the Company's Clean Energy Plan. After extensive modeling and analysis, the Company has refreshed its 2018 IRP and has developed a better plan for Michigan. The Company is seeking approval of an IRP in this case which will help Michigan lead a faster clean energy transformation by accelerating the Company's exit from coal-fired generation while increasing electric reliability and reducing energy market purchase volatility when compared to the Company's currently approved IRP. Through the acquisition of existing gas plants, and the continued commitment to key elements of the Company's Clean Energy Plan, the Company has developed an IRP which does not sacrifice reliability, affordability, or the financial stability of Consumers Energy.

In this proceeding, the Company is specifically seeking approval of a PCA which represents the most reasonable and prudent means of meeting the Company's energy and capacity needs over the 5, 10, and 15-year time horizons, consistent with Section 6t of Public Act 341 of 2016 ("Act 341"), MCL 460.6t. The continued expansion of solar, batteries, and demand-side resources in the PCA, near the levels included in the Company's 2018 IRP PCA, continue to demonstrate the Company's commitment to accelerating the Company's clean energy transition and the acquisition of existing gas resources will serve customers with reliable power while providing a bridge to a clean energy future. With the approval of the Company's PCA, the Company intends to continue filing IRPs every three years to address the level of uncertainty in the years beyond the first five years of an IRP's time horizon. The Company's PCA, which is inclusive of all other proposals presented by the Company in this proceeding, includes:

1) The accelerated retirement of the Company's D.E. Karn ("Karn") Units 3 and 4 from May 31, 2031 to May 31, 2023, J.H. Campbell ("Campbell") Units 1 and 2 from May 31, 2031 to May 31, 2025, and Campbell Unit 3 from December 31, 2039 to May 31, 2025, and the replacement of those resources with the purchase of existing gas resources, in addition to the expansion of the levels of solar and demand-side resources. The purchase of existing gas units will include the purchase of the New Covert Generating Facility ("Covert Plant") by May 31, 2023, and the purchase of the Dearborn Industrial Generation ("DIG Plant"), the Livingston Generating Station ("Livingston Plant"), and the Kalamazoo River Generating Station ("Kalamazoo Plant") by May 31, 2025. The accelerated retirement and purchase of the aforementioned resources are conditioned on: (i) approval of the Company's proposed regulatory asset treatment to recover the remaining net book balances of the above identified Campbell and Karn units through their current design lives and (ii) approval of the acquisition and total purchase price of the Covert, DIG, Livingston, and Kalamazoo plants ($1.345 billion), in the manner described in the Company's direct testimony and exhibits, as reasonable and prudent for cost recovery purposes pursuant to MCL 460.6t.

   These requests are designed to provide: (i) $640 million cumulative customer savings; (ii) long-term electric supply reliability, which is expected to be 90 times greater than otherwise achieved through the Company's currently approved IRP; (iii) a 50% reduction in energy market reliance which mitigates customer cost exposure to market volatility; (iv) continued expansion of demand-side and renewable resources at a pace to reach and give further opportunity to transform to a cleaner resource mix; (v) financial stability of the regulated electric utility; and (vi) immediate planet benefits by eliminating 63 million tons of carbon, reducing emissions of criteria pollutants such as sulfur dioxide ("SO_2"), nitrogen oxides ("NO_x"), mercury, and particulate matter, eliminate use of 220 billion gallons of fresh river and lake water, and eliminate 3 billion cubic yards of ash waste;

2) Accounting approvals related to the accelerated plant retirements. Specifically, the Company is proposing: (i) regulatory asset treatment to recover the remaining net book balances of Campbell Units 1, 2, and 3 and Karn Units 3 and 4 through their current design lives; (ii) approval to defer employee retention costs; and (iii) approval to make retirement transition costs a regulatory asset. The requested approval for the recovery of the remaining net book balances is necessary because the Company would be required to record an impairment for some portion of the above identified Campbell and Karn units if the Commission does not authorize a method of recovering the remaining net book balances of the plants, which includes the full recovery of financing costs, at the same time the PCA is approved. Approval of

regulatory asset treatment for expenses associated with community transition plans for the Karn site and the Campbell site and regulatory asset treatment for expenses associated with the Campbell retention and separation plan is necessary because these expenses have not been previously approved by the Commission and capturing these expenses in a regulatory asset will allow for future review and recovery of these costs if they are deemed to be prudent;

3) Approval of the selection and proposed purchase of the DIG, Kalamazoo, and Livingston plants by Consumers Energy from its affiliate, CMS Enterprises Company ("CMS Enterprises"). The transaction was a result of a competitive solicitation and is compliant with the Commission's Code of Conduct rules. The competitive solicitation also complied with the Federal Energy Regulatory Commission's ("FERC") standards for determining that an acquisition involving an affiliate will not adversely affect competition and is consistent with the public interest as it satisfied the four principles – Transparency, Definition, Evaluation, and Oversight – of FERC's solicitation guidelines. 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, Kalamazoo, and Livingston plants from CMS Enterprises;

4) Improvements to the Company's currently approved IRP competitive procurement process used to acquire the new supply-side resources in the Company's PCA (i.e. solar) which are primarily based upon learnings from the two competitive solicitations issued in years 2019 and 2020. These improvements include greater flexibility in the amount of capacity ultimately acquired in each solicitation and greater certainty regarding the Commission approval process for the new resources selected;

5) The continued use of the competitive procurement process for determining full avoided cost rates and the Company's capacity needs or sufficiency for the purposes of the Public Utility Regulatory Policies Act of 1978 ("PURPA"). However, the Company is requesting certain modifications to the Company's currently approved PURPA avoided cost construct, which includes changes to rate and contract eligibility. Furthermore, the Company is requesting a continuation of the Commission's determination that the Company does not have a PURPA capacity need so long as the Company is implementing the PCA, with the competitive procurement approach proposed by the Company;

6) Because the Company is seeking to continue a competitive procurement framework for the acquisition of new supply-side resources, the Company seeks to continue to recover a Financial Compensation Mechanism ("FCM") and apply the FCM to all new or newly modified PPAs. The Company is also proposing an adjustment to the methodology and level of FCM applied to PPAs, based on the FCM initially approved in Case No. U-20165; and

7) In addition to the requested approval of the acquisition and purchase costs of the Covert, DIG, Kalamazoo, and Livingston plants, as described above, and the 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 as reasonable and prudent for cost recovery purposes pursuant to MCL 460.6t. The total costs that the Company is seeking approval of include:

   a. $1.345 billion for the purchase costs related to the acquisition of the Covert, DIG, Kalamazoo, and Livingston plants;

   b. DR costs for January 1, 2023 to June 30, 2025 ($23,751,000 capital, $3,100,000 Operating and Maintenance ("O&M"), $26,300,000 of incentive, to achieve a total of 641 MW (657 Zonal Resource Credits ("ZRCs")) in 2025);

   c. EWR costs for January 1, 2024 to June 30, 2025 ($226,721,558 O&M, $45,344,312 of incentive, 545,305 MWh savings, 879 MW savings); and

   d. CVR costs for January 1, 2023 to June 30, 2025 ($9,736,315 capital, $1,203,14 O&M, 136,351 MWh savings, 56.81 MW savings).

Recovery of the purchase price of the Covert, DIG, Livingston, and Kalamazoo plants permit the Company to move forward with the purchase of those plants, which also enables the Company to accelerate the retirement of Karn Units 3 and 4 and Campbell Units 1, 2, and 3. Furthermore, the Company's near-term needs require an incremental 111.64 MW to a base plan of 1,576.81 MW of EWR, CVR, and DR that continue to track and grow at a trajectory like the PCA approved in the 2018 IRP. Finally, the continued procurement of solar and the initiation of battery development, together with the purchase of the Covert Plant and the DIG, Kalamazoo, and Livingston plants, are key components supporting the replacement of the capacity lost with the proposed accelerated retirement of the Company's above identified existing assets and the replacement of the capacity lost by the expiration of the PPA with Midland Cogeneration Venture Limited Partnership ("MCV") in 2030.

The Company's PCA embodies a truly balanced plan across People, Planet and Prosperity. It offers continued growth of clean renewable resources at or better than the levels identified in the approved 2018 IRP; greater electric supply reliability; greater customer savings realized in the short and mid-term years of the plan; near-term planet benefits due to reduction in carbon emissions, other air emissions, water, and waste; and financial stability of the regulated electric utility. The Company is committed to achieving Net Zero Carbon Emissions by 2040 for all generating resources to meet customers' needs and is well positioned to achieve this goal by continuing the efforts to support research and development, technology solutions to enhance operational flexibility of a dynamic electric system created by intermittent resources and demand-side management programs, and gaining learnings from the development of the solar glidepath identified in the PCA. Additionally, future learning opportunities pursued by the Company will help to accelerate the pace of the clean energy transformation with a mix of technology solutions.

The PCA is an integrated proposal that ties the evolution of the Company's resource portfolio to numerous proposals presented in this case (i.e., necessary expansion of solar, battery, and demand-side resources; purchase of existing gas resources; accelerated retirement of Campbell Units 1, 2, and 3 and Karn Units 3 and 4; and recovery of the remaining net book balances of the to-be-retired plants as a regulatory asset) which are necessary to make that resource portfolio evolution successful. Since the Company's PCA is a fully integrated proposal with numerous components, modification to or rejection of a proposal made in the PCA impacts the PCA's viability and the Company's willingness to execute on the remaining portions of the PCA not modified or rejected. As such, the Company reserves the right to abandon or amend its PCA if the Commission rejects any of the Company's proposals presented in this IRP.

SECTION I: IRP OVERVIEW

Q. Please provide an overview of statutory framework and filing requirements for IRPs.

A. Section 6t (1) of Act 341 required the Commission, within 120 days of the effective date of the act and at least every five years thereafter, to commence a proceeding that, among other things, establishes modeling scenarios and assumptions that each electric utility should include, in addition to the Company's own scenarios and assumptions, in developing its IRP.

On July 31, 2017, the Commission initiated Case No. U-18418 to implement the provisions of Section 6t (1) of Act 341. In its Order, the Commission directed the MPSC Staff to file a proposal to establish parameters related to the IRP process in the docket no later than August 31, 2017. The Order scheduled three public hearings in September 2017 and gave opportunity for written comments from any interested source to be submitted to the docket through October 20, 2017. The Commission approved Michigan Integrated Resource Planning Parameters on November 21, 2017, which included scenarios, assumptions, and sensitivities that must be included in each utility's IRP. On February 18, 2021, the Commission issued an Order in Case No. U-20633 directing Consumers Energy to include an additional scenario ("Carbon Reduction Scenario") inclusive of two carbon sensitivities in the Company's 2021 IRP filing.

In addition, Section 6t (3) of Act 341 required the Commission to issue an order establishing filing requirements, including application forms, instructions, and filing deadlines for an IRP filed by an electric utility whose rates are regulated by the

Commission. On October 11, 2017, the MPSC issued an Order in Case No. U-15896, et al requesting comments on draft IRP filing requirements and on draft alternative proposal filing requirements applicable in IRP cases and CON cases to comply with Sections 6t and 6s of Act 341. The Commission issued an Order on December 20, 2017 in that proceeding which adopted final filing requirements.

Q. Please explain the Company's 2018 IRP.

A. On December 21, 2016, Governor Rick Snyder signed into law Act 341, amending Public Act 3 of 1939. Effective April 20, 2017, Act 341 updated Michigan's energy laws for CON filings and established an IRP process and framework for electric utilities whose rates are regulated by the Commission. Specifically, Section 6t (1) of Act 341 required electric utilities to file an IRP with the Commission no later than April 20, 2019, and, at a minimum, every 5 years thereafter. The Company filed its IRP on June 15, 2018, the IRP to be filed under Section 6t of Act 341. On June 7, 2019, the Commission approved a settlement agreement which was supported, or not opposed, by 20 intervening parties and showed wide support and alignment from many stakeholders to create the best IRP for Michigan. At a high level the settlement agreement included:

- The approval of the Company's PCA 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 and a refresh of the evaluation is to be provided by the Company in a new IRP filing made by June 2021 to continue to show the plan is the most reasonable and prudent means of meeting the Company's energy and capacity needs;
- The pre-approval of costs for demand-side management programs in the first three years of the plan (2019-2022);
- The accelerated retirement of Karn Units 1 and 2 in 2023 and to seek recovery of the unrecovered book balance by no later than May 31, 2023;
- A Company-conducted retirement analysis of Campbell Units 1 and 2 which will be presented in the Company's 2021 IRP;

- A competitive bidding process to address future capacity needs of the Company during the IRP period and for determining the Company's PURPA avoided cost rates. The parties also agreed that the Company shall use a five-year outlook for determining capacity needs and that a PURPA capacity need does not exist for the Company if the Company is implementing its PCA as defined by the competitive bidding process;

- A 50% PPA and 50% utility ownership split of future supply-side capacity acquired through the competitive bidding process;

- Approval of an FCM on PPAs approved by the Commission on or after January 1, 2019, including PURPA contracts;

- Continued collaboration with the local transmission owners, Michigan Electric Transmission Company ("METC") and ITC Holdings ("ITC"), and with MISO; and,

- Various analysis and modeling requirements (i.e. stochastic risk assessment).

Q. Please provide an overview of the resources which make up the Company's currently approved IRP.

A. The Company's currently approved IRP, also known as the Company's Clean Energy Plan, contains the following key components:

- ~4,500 MW of solar by the year 2030 and over 6,000 MW by 2040;

- ~2,000 MW peak load reduction from customer efficiency programs (EWR, DR, and CVR);

- 450 MW of batteries by the year 2040;

- accelerated retirement of Karn Units 1 and 2 from May 31, 2031 to May 31, 2023;

- an assumed extension of the MCV contract from 2025 to 2030;

- Palisades PPA termination and site closure in 2022;

- Campbell Units 1 and 2 operating to May 31, 2031 and Campbell Unit 3 operating to December 31, 2039; and

- Karn Units 3 and 4 operating to May 31, 2031.

Q. Has the Company successfully implemented the 2018 IRP, as approved by the Commission?

A. Yes. To date the Company has been successful in the implementation of its approved IRP as evidenced by:

- The completion of the 2019 Solar Request for Proposal ("RFP") for 300 MWs planned to be operational in 2022. The Commission approved the 140 MW Calhoun PPA, the 150 MW Mustang Mile Build Transfer Agreement ("BTA"), and an open offering of 10 MW to PURPA Qualifying Facilities ("QFs") at the Commission-approved full avoided cost rate set by the Mustang Mile BTA. See Case No. U-20165, April 8, 2021 and May 26, 2021 Orders;

- The issuance of the 2020 Solar RFP for 300 MW planned to be operational in 2023. Contract negotiations are in progress;

- The development of the 2021 Solar RFP for 500 MW planned to be operation in 2024;

- The method for recovery of the FCM was established in the Company's 2020 electric rate case, Case No. U-20697;

- The Commission approved an amendment to extend the term of the Palisades PPA until May 31, 2022, which provides customers capacity from Palisades for the entire 2021/2022 MISO Planning Year, in an August 20, 2020 Order Approving Settlement Agreement in Case No. U-20734;

- The Commission approved an amendment to extend the MCV PPA from 2025 to 2030 in a March 4, 2021 Order in Case No. U-20896;

- The Company has acquired the customers to account for 461 MW of DR for MISO Planning Year 2021;

- The Company has achieved 1.6% savings equivalent to 1.8% savings in 2020 and is on track to meet or exceed the 2% 2021 savings target projected in the Company's currently approved IRP;

- The Company has achieved 5.7 MW and 5,643 MWh of CVR within projected costs for 2020; and

- The Company has contracted with, and is bringing online, 519 MW of 525 MW of wind and 100 MW of solar by end of 2021 as planned in the REP.

The Company's successful implementation of the 2018 IRP sets forth a trajectory to meet the objectives the Company established in 2018 of being coal free by 2040, reducing carbon emissions for its owned resources by 80% from 2005 levels, and the cost of the plan being less than inflation for customers.

Q. Why has the Company filed this IRP?

A. As discussed above, as part of the settlement agreement approved in Case No. U-20165, the Company's 2018 IRP, the parties agreed that the Company would file its next IRP in June 2021. This filing represents a "refresh" of the Company's approved 2018 IRP and is intended to ensure that the Company's approved IRP continues to represent the most reasonable and prudent plan to meet the Company's energy and capacity needs.

As part of the IRP refresh, the Company assessed its capacity resource portfolio considering capacity needs, electric supply reliability, cost, environmental requirements and goals, financial impacts, diversity, and risk. The assessment also sought to provide customers with more options for sustainable and renewable resources, a consistent theme heard from stakeholders. In doing so, the Company has provided a comprehensive IRP that, after stakeholder input, modeling, and analysis, represents the most reasonable and prudent course of action to meet customer capacity and energy needs that is clean, reliable, and affordable now and in the future.

Q. Please provide a summary of utility and industry changes since the approval of the Company's IRP?

A. Over the past two years the electric utility industry and the Company have seen many changes putting the Company in a position to re-evaluate and consider additional components of the currently approved IRP. The most significant of those changes are the energy and capacity markets, regulatory environment on Climate Change at the state and federal levels, the need and expectation of environmental, social, and governance ("ESG") considerations to the Company's plans from the investor community, customer feedback to be cleaner faster while being affordable and reliable, the Company's evolved decarbonization goal to be net zero by 2040, and the long-term performance risks of an aging coal fleet and the oil/gas peaking units.

Q. What has changed in the capacity and energy markets?

A. Leading indicators from across the United States identify potential risks to electric supply reliability as the electric industry shifts from traditional controllable generation (i.e. coal) to greater levels of intermittent and demand-side management programs. This is evidenced by MISO conducting workgroup sessions to design a resource adequacy construct better able to plan across all seasons in the MISO footprint to mitigate non-traditional peak demand concerns (i.e. winter months) and the traditional coincident peak occurring in the summer months of July and/or August. Additionally, the North American Reliability Corporation ("NERC") issued its 2020 State of Reliability – An Assessment of 2019 Bulk Power System Performance[1] in July 2020 flagging continued risks of Electric Reliability Council of Texas not meeting its Planning Reserve Margin Requirements ("PRMR"). NERC identified the need to address system protection and system needs as electric utilities across the nation replace greater levels of controllable generation with dynamic uncontrollable technologies. Lastly, MISO has long indicated the potential of Zone 7 (the majority of Michigan's lower peninsula) to be short in

[1]NERC's report can be publicly accessed on the NERC website and the following link: https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2020.pdf?inf_contact_key=98e13b066dfb15f6bde904a414695c0c680f8914173f9191b1c0223e68310bb1

meeting its local resource needs the next five years due to the level of demand-side management programs and new planned resource builds not yet in the process of being constructed or operational. These changes and indicators are further discussed by Company witness Thomas P. Clark.

Electric supply reliability is a core necessity of any resource plan. The Company has an obligation to create a clean plan that de-risks its customers, the state, and the Company from the potential lack of resources necessary to meet energy and capacity needs during extreme weather events, the level of availability from intermittent resources and demand-side management programs, and locating/bringing resources to the state of Michigan rather than a reliance on new resource builds outside of the state. The Company offers a plan that provides this and the flexibility to adapt its plan to the changing needs of customers and the system with the ability to potentially create new jobs and revenue for Michigan.

Q. What has changed in the regulatory environment to address climate change?

A. In the past two years the Company has seen three different sets of regulation at either the state or federal level regarding climate change by way of legislation or executive targets. At the federal level, the Biden Administration issued a goal to have a carbon free power sector by 2035, economy-wide carbon neutrality by 2050, and to rejoin the Paris Climate Agreement. The Paris Climate Agreement seeks to limit average global temperature to 2° C, and preferably 1.5° C. To reach the 2° C goal, global economy-wide greenhouse gas emissions must reach net-zero by approximately 2070. To reach the 1.5° C goal, greenhouse gas emissions must be reduced by 40-60% by 2030 and be net-zero by 2050. Consistent with the 1.5° C goal, both the Biden Administration and Governor Whitmer (as part of the MI Healthy Climate initiative) have announced net-zero by 2050 goals. Additionally, Governor Whitmer set a near-term target of achieving a 28% reduction in economy-wide carbon from a 2005 baseline by the year 2025 in Executive Directive 2020-10. Prior to President Biden's and Governor Whitmer's targets being announced, the Company made a public commitment to achieving Net Zero Carbon Emissions that considers all sources of generation used to serve its customers (owned, contracted, and market) by 2040, surpassing other target dates set by administrations at the time. The Company remains committed to the higher standard of reducing all sources of generation to serve its customers to reach Net Zero Carbon Emissions by 2040. The Company's PCA, as proposed in this IRP, puts the Company on track to exceed the Paris Climate Agreement scenarios and the Governor's MI Healthy Climate targets. The Company's PCA also puts the Company in the position to have many options to choose from over the next 20 years to achieve its commitment to the planet. This is further discussed by Company witness Heather A. Breining.

Q. What has changed from the public and investor communities?

A. As further described in the Stakeholder Engagement Report, Exhibit A-2 (RTB-2), and in my direct testimony, the Company received a range of public comments, but a common theme in the comments was a focus on the need to transform to a cleaner resource mix sooner rather than later while continuing to be affordable and reliable.

From an investment community perspective, including select banks, there is typically some form of coal exclusion criteria. Passive investors, such as index funds, that focus on ESG typically have a 5% coal threshold. Utility investors, who focus primarily on the sector, are carefully evaluating utilities to ensure compliance with current regulations, including the Paris Climate Agreement, and future mandates. Over time, the sentiment will continue to evolve and will likely move toward a binary yes/no investment decision on utilities that still own coal, which could put customer's investments at risk.

Q. What has changed in the age and operational performance of the coal and oil/gas peaking units?

A. The age and operational performance of Campbell Units 1 and 2, which are coal units, and Karn Units 3 and 4, which are oil/gas peaking units, have provided a basis to reevaluate the Company's approved IRP. The age of Campbell Units 1 and 2 are 59 and 54 years, respectively. Furthermore, the age of Karn Units 3 and 4 are 64 and 44 years, respectively. These units have served customers over the last five decades with economical and reliable power and do have remaining value in their design lives. However, these units are nearing or have surpassed the point of which the Company would expect to begin to experience a reduction in operational performance due to asset age. For instance, Figure 1 below is from the MISO Transmission Expansion Planning ("MTEP") Futures 2019 assumptions and illustrates the utility choice to retire a coal unit exponentially increases after the age of 55. The operational performance of Campbell Units 1 and 2 have seen periodic issues over the last two years. The periodic operational performance issues experienced at these units serves as a leading indicator of increasing risk as to the overall operational performance of the units going forward and the value customers are to realize with the continued operations of the units.

Figure 1: MISO Historical and NREL Assumed Age Retirements (MISO, 2019)[2]

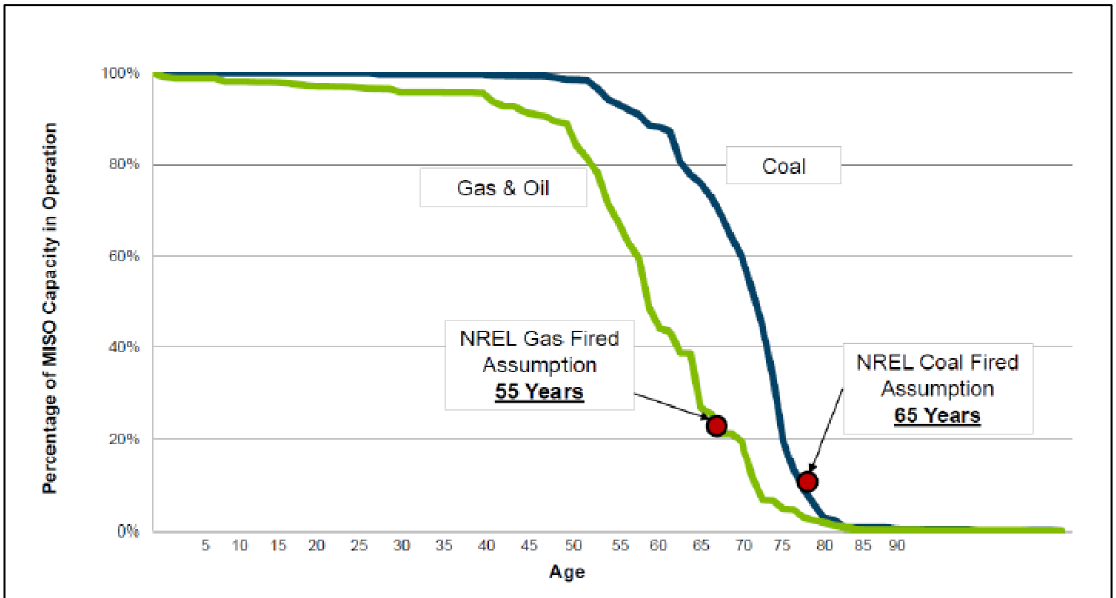
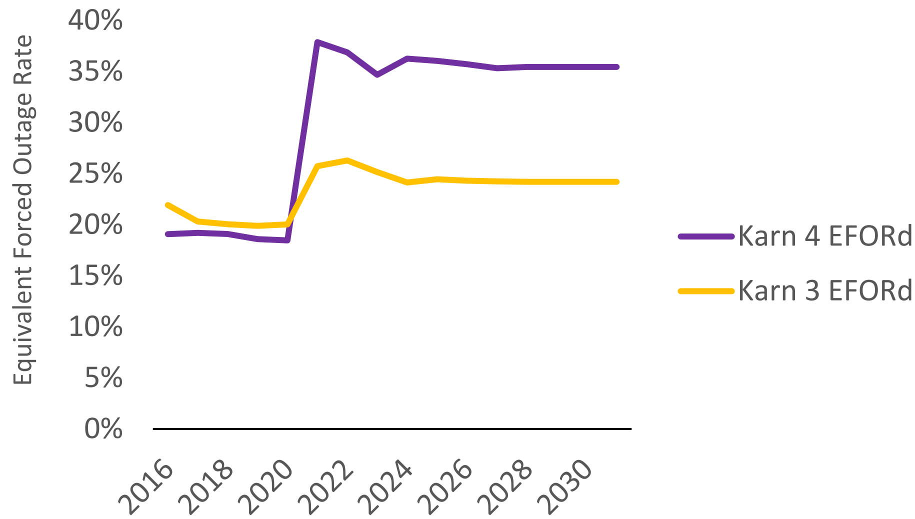


Figure 10: MISO Historical and NREL Assumed Age Retirements

Karn Units 3 and 4 have had similar operational issues, as evidenced by the forced outage rate ("EFORd") actuals starting in 2016 and the projected EFORd levels to 2031. Operational performance of the Campbell and Karn units is further discussed by Company witness Norman J. Kapala.

[2] MISO MTEP 2019 Futures Report, Appendix E, Figure 10, MISO Historical and NREL Assumed Age Retirements, page 17.

<u>Figure 2: Karn Units 3 and 4 EFORd Actual and Projections 2016-2031</u>



While the age and performance of the units have shown signs of operational strain, Karn Units 3 and 4 and Campbell Units 1 and 2 continue to provide benefits today and are expected to continue to provide those marginal benefits through their current design lives. Campbell Unit 3 is a newer asset (41 years old) and has not experienced the same issues. However, the planet, economic, community, and co-worker benefits (i.e., accelerated pace to begin to seek positions) of accelerated retirement outweigh the continued operations of this site if the Company is able to recover the remaining net book balances of Campbell Units 1, 2, and 3 and Karn Units 3 and 4 as a regulatory asset consistent with the original design lives of the units.

Q. Does this IRP filing meet the Commission's requirements?

A. Yes. This filing meets the requirements set forth by the Commission in Case No. U-18418 (Michigan IRP Modeling Parameters), Case No. U-15896, et al (Michigan IRP Filing Requirements), and Case No. U-20633 (Emissions Reporting). The Company's filing also meets the requirements in Section 6t of Act 341. Exhibit A-1 (RTB-1) details each IRP filing requirement and the corresponding location of responsive information in the Company's filing. It should be noted that this exhibit is intended to direct a reviewer of the Company's filing to information filed by the Company which addresses a certain filing requirement and does not provide an exhaustive list of all information which may be applicable to a certain filing requirement.

Q. Please provide an overview of the witnesses and the topics for which they will present evidence in support of this IRP filing.

A. There are 23 witnesses presenting evidence in support of this IRP filing.

Company witness Sara T. Walz describes and supports the scenarios and sensitivities used to develop the IRP, to assess the accelerated retirement cases, and to meet the requirements of the Commission's Orders (Case Nos. U-18418 and U-20633) on IRP Modeling Parameters. Company witness Walz also provides details regarding cost and economic support for plans resulting from the PCA.

Company witness Anna K. Munie describes the risk assessment methodology utilized and the results of that analysis.

Company witness Kapala presents the existing electric generating assets under the Company's control and operation and the estimated cost to operate and maintain Karn Units 3 and 4 and Campbell Units 1, 2, and 3 as proposed in the PCA. Additionally, Company witness Kapala describes the separation costs related to: (i) the proposed accelerated retirement of Karn Units 3 and 4 and Campbell Units 1, 2, and 3; (ii) the estimated costs to operating and maintaining the Covert, DIG, Livingston, and Kalamazoo plants; (iii) community and co-worker impacts; and (iv) the actions that will commence within three years after a final order in this proceeding.

Company witness Eugène M. Breuring provides detail about how the forecast of electric sales, maximum demand, and system output is developed, including the process used to account for EWR and DR. Company witness Breuring also supports the reasonableness of the electric sales forecast used in this IRP.

Company witness Benjamin T. Scott describes engagement efforts with local transmission owner, METC/ITC, the reasonableness of the studies conducted by METC/ITC on the Company's behalf, and the analysis involving MISO and the MPSC's Capacity Import Limit ("CIL") studies.

Company witness Brian D. Gallaway describes the Company's current fuel procurement practices, supply arrangements, and costs associated with existing generating facilities. Company witness Gallaway discusses the fossil fuel price forecasts used in the IRP process, as well as the expected fuel type, supply, costs, and contractual agreements associated with the PCA. Additionally, Company witness Gallaway discusses the fossil fuel price forecasts, supply, costs, and contractual agreements of the Covert Plant and the DIG, Kalamazoo, and Livingston plants.

Company witness Teresa E. Hatcher compares the current REP assumptions to those in the PCA and discusses the consistency between the IRP and the REP. The comparison describes the renewable energy assumptions specific to utility-scale wind and solar resources utilized in the IRP processes. Company witness Hatcher also discusses the Renewable Portfolio Standards and renewable energy goals related to Public Act 342 of 2016. Additionally, she describes customer interest in renewables and energy saving resources to meet sustainability goals.

Company witness Jeffrey E. Battaglia describes the practicality and execution risk surrounding the development of the renewables specified in the PCA and describes the modeling assumptions developed for gas-fueled, solar, batteries, and net zero carbon emission technologies. Additionally, Company witness Battaglia gives an overview and description of the bid proposals and agreements to purchase the Covert Plant and the DIG, Kalamazoo, and Livingston plants.

Company witness Nathan J. Washburn describes the value component assumptions of energy storage technologies.

Company witness Clark describes resource adequacy and the market constructs that exist today and potential changes to those constructs and maintaining day-to-day system operability.

Company witness Carolee Kvoriak explains the Production Tax Credit allowed under Section 45 of the Internal Revenue Code ("IRC"), the Investment Tax Credit allowed under Section 48 of the IRC and other federal tax credits allowed for renewable and alternative technologies. Company witness Kvoriak also explains taxes related to the purchase of the Covert Plant and the DIG, Kalamazoo, and Livingston plants.

Company witness Teri L. VanSumeren gives a policy overview of the Company's customer programs and their benefits. These programs include EWR, DR, CVR, Voluntary Green Pricing ("VGP"), and electric vehicle programs.

Company witness Emily A. McGraw discusses the Company's existing and proposed demand-side management programs and describes the DR assumptions utilized in the IRP process. In addition, Company witness McGraw explains the historical performance of DR as pre-approved in the 2018 IRP and the levels of DR included as part of the PCA, and describes the costs associated with DR programs that will commence within three years after a final order in this proceeding for which the Company is seeking Commission approval for cost recovery, as provided by Section 6t of Act 341.

Company witness Steven Q. McLean discusses the Company's existing EWR programs and describes the EWR assumptions utilized in the IRP process. Further, Company witness McLean explains the historical costs and performance of EWR as pre-approved in the 2018 IRP and describes the costs and cost recovery involved in achieving the levels of EWR as described in the PCA that will commence within three years after a final order in this proceeding for which the Company is seeking Commission approval for cost recovery, as provided by Section 6t of Act 341.

Company witness Lakin Garth, a consultant from Cadmus, discusses the approach and results of the Company's potential studies performed in 2019 through 2020 for EWR and DR programs.

Company witness Matthew S. Henry discusses the Company's CVR program and describes the assumptions used in the IRP process. Company witness Henry explains the customer benefits from an electric distribution and supply-side perspective, and how the Company's grid modernization efforts are leveraged to realize these benefits. Additionally, Company witness Henry describes the costs associated with CVR that will commence within three years after a final order in this proceeding for which the Company is seeking Commission approval for cost recovery, as provided by Section 6t of Act 341.

Company witness Sarah R. Nielsen discusses the Company's VGP and electric vehicle programs and the assumptions utilized in the IRP process.

Company witness Heather A. Breining describes the environmental regulations electric utilities must comply with and which apply to the Company's electric generating fleet, the cost of compliance with those regulations as they apply to Company's generating assets, as well as the timing and justification for the investments made to ensure environmental regulatory compliance and creating a better plan for Michigan. Company witness Breining also includes an environmental justice assessment of the PCA and how the PCA achieves the Company's planet goals and state and federal climate goals. Company witness Breining also addresses environmental considerations related to the purchase of the Covert Plant and the DIG, Kalamazoo, and Livingston plants.

Company witness Jason R. Coker explains the financial assumptions used in the IRP model, and provides an estimated customer rate impact of the PCA and an alternate plan. Company witness Coker also discusses the necessary regulatory treatment and recovery of the remaining unrecovered net book balances to retire Karn Units 3 and 4 and Campbell Units 1, 2, and 3 before the end of their design lives (2031 for Karn Units 3 and 4 and Campbell Units 1 and 2, and 2039 for Campbell Unit 3).

Company witness Kevin J. Watkins describes the projected unrecovered remaining book balances associated with Karn Units 3 and 4 and Campbell Units 1, 2, and 3, and the depreciation impacts for the early retirement of these units using the depreciation schedule and rate currently approved by the MPSC and using accelerated depreciation. Company witness Watkins also describes the projected decommissioning and ash disposal costs for the aforementioned plants and other retired coal assets owned by the Company.

Company witness Srikanth Maddipati explains the Company's proposed adjustments to the FCM which provides an incentive for executing PPAs, as authorized by Section 6t (15) of Act 341, and the financial benefits of the proposed method of recovering the remaining unrecovered net book balances for Karn Units 3 and 4 and Campbell Units 1, 2, and 3.

Company witness Keith G. Troyer explains the existing contractual agreements for capacity and energy, and the assumptions associated with these contracts. Company witness Troyer also presents the Company's proposed improvements to the Company's IRP competitive procurement process used for acquiring the new supply-side resources identified in the PCA and for determining a PURPA capacity need. Furthermore, Company witness Troyer presents improvements to the Company's PURPA avoided cost rate construct. Company witness Troyer also provides an overview and results of the RFP issued for existing gas facilities in January 2021.

Q. Has the Company developed a report to supplement this IRP filing?

A. Yes. I am sponsoring the Company's IRP report, which appears as Exhibit A-2 (RTB-2). The Company's IRP report meets the Commission's filing requirements and provides, among other things, the Company's analysis and decisions in selecting its PCA and resource evolution strategy.

SECTION II: IRP OBJECTIVES AND PRINCIPLES

Q. What planning objectives did the Company set as it performed this IRP?

A. Section 6t of Act 341 requires the Commission to approve an IRP if it determines the plan represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs. To make this determination, the Commission shall consider whether the plan appropriately balances all the following factors:

i. Resource adequacy and capacity enough in quantity to serve anticipated peak electric load plus applicable PRMR and Local Clearing Requirement ("LCR");

ii. Compliance with applicable state and federal environmental regulations;

iii. Competitive pricing;

iv. Reliability;

v. Commodity price risks;

vi. Diversity of generation supply; and

vii. Whether the proposed levels of peak load reduction and EWR are reasonable and cost effective.

In the context of the Commission's definition of what constitutes the standard for the most reasonable and prudent plan, the Company examined its own planning objectives. The Company's planning objectives are based upon its commitment to create a plan balanced across the Triple Bottom Line - People, Planet, and Prosperity. The Commission's and Company's planning objectives are well aligned and, when taken together, result in a better plan for Michigan.

People

From a *People* perspective, the Company must recognize and address the impact the PCA has on communities, employees, and customers. The Company will respect and care for employees and communities affected by any changes to its resource portfolio. This includes finding employment for Company personnel displaced by unit retirements when possible and helping communities to reimagine the local economic landscape.

Electric supply reliability is central to the Company's *People* commitment. Providing enough capacity to serve anticipated peak electric load plus applicable PRMR and LCR results in reliable energy supply (Commission objectives i and iv) and preparing for extremes in shifting electric need throughout the year. It is of great importance for a utility to create a plan agile and adaptable to dynamic changes in energy needs. Additionally, the Company's flexibility to make economic market purchases of power, reducing the Company's exposure to the volatility of the energy market.

A commitment to *People* also includes listening to customers regarding their desire for Michigan's energy future and corresponding evolution of the Company's resource portfolio. Conducting stakeholder outreaches during the IRP allows opportunity to integrate customers' desires and needs into the IRP process.

Minimizing customer rate impact is also an important *People* consideration. This is supported through minimizing, to the extent possible, capacity replacement costs, remaining book balance for potential retirement scenarios, execution risk for resource planning, stranded fuel obligations, and reliance upon less reliable equipment.

<u>Planet</u>

From a *Planet* perspective, the Company must ensure the PCA meets Renewable Portfolio Standards specified in Michigan law and compliance with applicable state and federal environmental regulations (Commission objective ii). Transitioning to a clean and lean resource portfolio positions the Company to achieve compliance with potential environmental regulation that may be imposed in the future, such as carbon dioxide emissions regulations, which reduces future financial risk to customers. The PCA must also align with the Company's Clean Energy Goals, which extend beyond the compliance level required by current law and illustrates the Company's deep commitment to protecting the environment. The Company's Clean Energy Goal strives to be coal free and set a course for reaching Net Zero Carbon Emissions for all generating sources used to meet customer needs by 2040.

Prosperity

From a *Prosperity* perspective, the PCA must provide for both a financially healthy utility that attracts capital investment for needed electric infrastructure and affordable bills for customers. In a traditional utility regulatory environment, utility investors earn returns on capital investment in new infrastructure. This traditional regulatory model gives little incentive for utilities to utilize PPAs to meet energy and capacity needs. MCL 460.6t appropriately authorized the Commission to approve a new financial and regulatory system by providing fair and reasonable compensation for utilities that utilize PPAs. The Commission's adoption of such compensation is critical to creating a stable, sustainable regulatory and financial model that drives utilization of PPAs that benefit the Company's customers and the state of Michigan. The PCA must also provide for affordable customer bills and competitive pricing (Commission objective iii), which are critical to support the lives of the Company's residential customers and the businesses of its commercial and industrial customers. The investment by the Company in Michigan and supplying resources within Michigan is key to the prosperity and economy of Michiganders because it creates an opportunity for local tax revenue and job creation.

Furthermore, a supply plan that is modular lessens customer rate impact as it provides flexibility to adjust to changes in technology cost, electric demand, or the business environment. This approach is a departure from the traditional utility model of pursuing new large, centralized generation projects to realize economy of scale benefits, which can result in the risk of inflexible supply, particularly when actual demand falls short of forecasted demand. This can be addressed with a lean portfolio that involves reasonable and cost effective EWR (Commission objective vii). A modular approach provides a scalable supply portfolio that minimizes potential for surplus capacity, diversifies supply resources (Commission objective vi), insulates the Company and its customers from commodity price risks, and protects against high customer rates (Commission objective v).

Q. What are the key decisions the Company set out to address in this IRP?

A. The key decisions of the IRP and the resulting PCA was to create the most reasonable and prudent means of meeting short- and long-term energy and capacity needs. In reaching this result, this IRP necessarily had to address six key decisions.

First, the Company had to ensure the PCA achieved all planning objectives set forth by the Commission and the Company.

Second, the Company had to develop an analysis regarding the accelerated retirement of the baseload coal units and the oil/gas peaking units. This analysis was needed to support Company planet goals to exit coal faster, as well as the goals of the Biden Administration and Governor Whitmer, while maintaining a similar or improved pace of solar, battery, and demand-side resource expansion and create a path forward to achieving Net Zero Carbon Emissions by 2040 for all sources used to serve customers. As part of the settlement agreement approved by the Commission in Case No. U-20165, the Company was also required to perform an accelerated retirement analysis of Campbell Units 1 and 2 which specifically examined the potential retirement of those units in isolation and together, in years 2024, 2025, 2026, and 2028, as well as the continued operation of the units through their end-of-design lives in 2031. The accelerated retirement of Campbell Unit 3 was included in the analysis after leading indicators in the Campbell Units 1 and 2 results identified potential solutions to exit coal while continuing to serve customers reliably. Additionally, the Company examined the accelerated retirement of Karn Units 3 and 4 as early as 2023 and no later than 2025. By accelerating retirement of these units at or near the same year as the currently approved retirement year for Karn Units 1 and 2 (i.e. 2023), the communities around the Karn generation site are better positioned to create greater redevelopment opportunities at a quicker pace, a quicker transition for Company co-workers, and to mitigate operational performance risks for customers by replacing with resources able to provide capacity and greater levels of energy production throughout the year.

Third, the Company sought to develop a PCA capable of long-term electric supply reliability while still achieving the goal of being cleaner faster. The capability to provide long-term electric supply reliability includes the Company’s flexibility to choose the best way to economically serve customer energy needs by either operating the Company’s controllable generation or making purchases from the MISO market. This approach is superior to a portfolio heavily reliant on intermittent resources which forces market purchases to serve customers in all hours of the year whether economic or not to do so.

Fourth, the Company sought to identify financial solutions for the recovery of the remaining net book balances created with accelerated retirements of Campbell Units 1, 2, and 3 and Karn Units 3 and 4 which give financial stability to the Company and in turn creates economic stability and benefits to Michigan.

Fifth, the Company sought to continue to seek competitive pricing for supply options that mitigates future cost risks for customers. The Company proposes the continuation of the currently approved competitive procurement process, with certain adjustments, for procuring capacity and energy through competitive bids and the use of that process to determine PURPA avoided costs because it provides the most accurate representation of the costs that the Company actually avoids by purchasing from a QF, and provides an orderly process for the acquisition of capacity and energy at competitive pricing. The competitive procurement of supply-side resources identified in the Company's PCA will continue to involve an annual solicitation process. However, greater flexibility is needed for the amounts procured on an annual basis. The Company will focus on targeted amounts identified in the Company's PCA, rather than a precise annual limit of MWs to be provided. This approach provides the Company with a greater ability to attain the most economic and valuable projects for its customers and is a recognition of the unrealistic process of acquiring an exact amount MW year over year from a solicitation process. The Company will base the final capacity amount acquired each year on economics and the outcome of the negotiation process. The Company also intends to pursue an ownership structure which includes acquiring at least 50% of new capacity from Company-owned resources and the remaining 50% from PPAs or Company-owned resources, based on economics, and will seek to achieve at or near this split in each solicitation as opposed to meeting the targeted ownership split in each solicitation. Future IRPs will adjust the procurement amounts based upon the results of past solicitations.

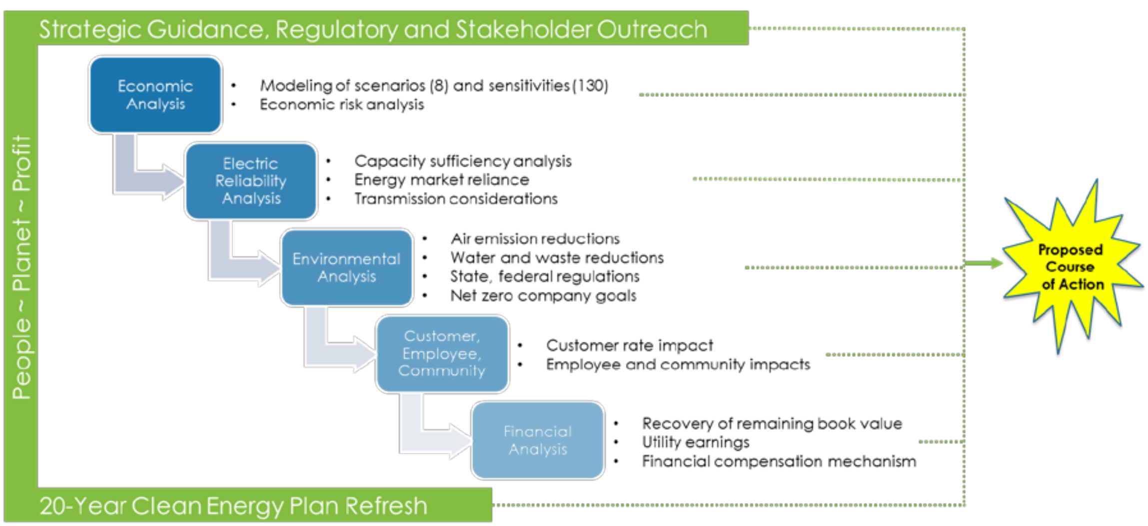
Sixth, because the Company is proposing to continue the competitive procurement process with modifications, the Company sought to continue the FCM. The Company proposes the FCM be applied as a fair return on PPAs at an adjusted pre-tax Weighted Average Cost of Capital. A PPA incentive helps align the Company's and customer interests by removing potential bias toward utility-owned assets. This alignment of interests allows customers to access potentially lower cost supply alternatives while providing a fair return. This approach is reasonable and compliant with Act 341, Section 6t.

<u>SECTION III: IRP PROCESS</u>

Q. Please summarize the process used by the Company to complete this IRP.

A. The IRP process starts with the identification of the principles and compliance requirements as previously discussed. Traditionally, IRPs have been associated with capacity expansion models able to run probabilistic analysis to determine the lowest cost resources available to meet a utility's coincident peak load requirement plus a reserve margin which equates to a utility's PRMR. The coincident peak load historically occurs in the heated months of July and August. The capacity expansion models are powerful tools used to stress test future scenarios, sensitivities, and possibilities to determine cost impacts to customers. At the same time, the Company engages stakeholders inclusive of the general public, interested parties that typically intervene in the Company's electric rate case proceedings and IRPs, and the local transmission owner to discuss development of the IRP, receive feedback, and obtain analysis from the transmission owner to support determining the resources needed to meet future capacity and energy needs. Consumers Energy supplements the stakeholder feedback and the capacity expansion economic analysis by incorporating electric supply reliability analysis, environmental impact analysis, customer-employee-community impacts, and financial analysis. Hundreds of cases and thousands of iterations are conducted to output various options and solutions to creating a balanced PCA. This is further defined in Figure 3.

<u>Figure 3: Integrated Resource Plan Process and Key Analysis</u>



Q. Please summarize the Capacity Expansion Economic Analysis in the IRP Process.

A. The Company first identifies the capacity position based upon existing and approved resources planned through the 20-year study horizon and whether a capacity need exists in the first three years. If a capacity need exists in the first three years, the Company would issue an RFP per MCL 460.6t(6) to obtain information on potential economic resources available to meet that need. The Company did not identify a capacity need in the first three years, as shown in Figure 4 below, and did not issue an RFP prior to the development of the IRP. Second, effort is taken to create scenarios and sensitivities representing a wide range of potential future outcomes. Once the scenarios and sensitivities were established, there was an intense period of modeling and analytical work completed using resource planning software. In the case of Consumes Energy, this software is called Aurora and is provided by Energy Exemplar. Further details of this analysis are provided in the direct testimony of Company witness Walz. During this period, the Company conducted three technical workshops, four virtual public outreaches, and various one-on-one discussions with interested parties with the purpose of informing, educating, and collecting stakeholder thinking for consideration in the creation of the IRP. These outreaches gave an opportunity to address their concerns and continue to understand the diverse perspectives of meeting future capacity and energy needs.

The output generated from the capacity expansion model, co-optimizing both capacity and energy, is assessed for risk. A risk assessment is performed on each resource plan. The risk assessment is intended to identify potential cost and reliability risks with a resource plan due to uncertainty, volatility, or unexpected events in the forecasts and assumptions used in the model. The risk assessment methods used in the analysis include the comparison of the net present value ("NPV") revenue requirement between scenarios and sensitivities to a reference point, the modeling of each optimized portfolio through all scenarios, and the use of stochastics on each optimal plan to identify risks to cost and reliability of each optimal plan when identified risk variables are given the latitude to change within set bounds and iterations. The direct testimony of Company witness Munie describes the approach and results of the risk assessment.

Q. Please summarize the Electric Reliability Analysis in the IRP Process.

A. The Company evaluates electric reliability by analyzing a resource plan's capability to provide sufficient capacity to serve projected customer demand by varying a set of parameters influencing the outcome (i.e. generator availability), the level of market reliance for capacity and energy to serve customers, and a transmission analysis to identify additional costs, savings, or constraints.

To determine the capacity sufficiency of a resource, the Company utilized a type of Loss of Load Expectation ("LOLE") Study as required in the settlement approved in the 2018 IRP. The paragraph 13, item (m.), of the settlement agreement specifically required the Company to include:

> Results of a loss of load expectation study to assess the potential change in either the frequency or durations of curtailments and the role of DR in meeting peak demand. The study should reflect the impact of varying generation capcity mix scenarios, including the PCA and varying amounts of DR.

To meet this requirement the Company utilized Aurora to conduct an LOLE Study similar in nature to the resource adequacy study conducted by MISO with a few exceptions. Those exceptions include evaluating the Company's resource plan as an island and the ability for it to access the market up to 3,200 MWs. The 3,200 MW assumption was made based upon the CIL determined by MISO in their Planning Year 2020/2021 LOLE Study. The Company uses the 3,200 MW resource to represent the ability for electric utilities to share resources within MISO to provide the most economic means of serving customer load as is done today in MISO. The 3,200 MW is not intended to assume that import capability is only available to Consumers Energy; however it is an indicator of whether a resource plan carries a risk of market exposure. The MISO market constructs are further discussed and detailed in the direct testimony of Company witness Clark. The LOLE Study conducted by the Company is further detailed in the direct testimony of Company witness Walz.

The Company evaluated the level of energy and capacity market reliance of the resource plan. For capacity market reliance, the LOLE Study is used to understand the number of consecutive hours, days, and amount of the market purchases for capacity in the year 2032, the first year of full operations of the generating fleet with reduced controllable fossil generation, under varying conditions. A resource plan relying fully on the CIL or market of 3,200 MW in consecutive hours and days over a majority of the year indicates significant risk to the Company in serving its customers reliably. As an example of this, the Alternate Plan on average relies on 32% of the CIL capability while the PCA relies on 17% of the total import capability. Instead, if, on a typical day, a portfolio indicates customer demand is predominantly served by the Company's existing and planned resources, like the PCA, this indicates minimal risk of serving customers reliably. For energy market reliance a year-by-year assessment of energy supply is evaluated to determine the level of market purchases. The greater the percent of market reliance on energy the greater the exposure to increasing costs due to volatility in the market.

Transmission analysis was conducted by the local transmission owner METC/ITC. The analysis requested by Consumers Energy of METC/ITC focused on network upgrade and interconnection costs for assets connected to the transmission system (138 kV and up) and transmission expenses as a revenue requirement for potential transmission projects needed to address transmission issues. These additional costs and insights are considered in the development and selection of a resource plan. The details of the analysis are described in the direct testimony of Company witness Scott.

Q. Please summarize the Environmental Impact Analysis in the IRP Process.

A. The Company evaluates environmental benefits of a resource plan by assessing impacts to air emissions, water usage, waste creation and/or elimination, and land impacts due to new resource builds or potential for re-purposing. The air emissions evaluated by the Company include carbon emissions from a 2005 baseline, NO_x, SO_2, particulate matter, and mercury. The water usage/savings are based upon annual gallons used for cooling systems of thermal units. The creation or reduction of waste is based upon annual coal ash production. Land use is a qualitative measure of the ability to redevelop or repurpose coal asset site locations and the siting of new resource builds benefiting the environment. Additionally, an assessment is made on the state and federal regulatory proposals and requirements impacting a regulated electric utility's resource plan such as Executive Directive 2020-10 issued by Governor Whitmer on September 23, 2020 setting a goal to reduce carbon emissions from the 2005 baseline by 28% economy-wide by the year 2025. Finally, the Company compares resource plans to understand their ability in achieving the Company's planet goals. The Company had a prior goal from the 2018 IRP to be coal free by 2040 and reduce carbon emissions by 80% from a 2005 baseline. The Company later evolved this metric to a Net Zero Carbon Emissions by 2040 goal for all sources of generation; a higher standard to achieve than only evaluating Company-owned assets.

The direct testimony of Company witness Breining further explains the Environmental Impact Analysis.

Q. Please summarize the Customer Rate, Employee, and Community Impact Analysis in the IRP Process.

A. The Company analyzes the customer rate impact by way of an incremental revenue requirement analysis to determine year-over-year rate impacts, the plan's Compound Annual Growth Rate ("CAGR"), and the potential for customer savings through rates over the planning period. This customer rate impact analysis is further detailed in the direct testimony of Company witness Coker. The employee and community impacts analysis for a resource plan is evaluated for the number of co-workers impacted by the resource plan, the time and resources needed to safely and effectively transition co-workers and retire assets, the level of tax revenue impacts to the local community, and an evaluation of vulnerable communities with decisions related to retirement of fossil assets or additions of new fossil assets. The employee and community impacts are further detailed by Company witness Kapala. The evaluation of vulnerable communities is further detailed in the direct testimony of Company witness Breining.

Q. Please summarize the Financial Analysis in the IRP Process.

A. The financial analysis used to compare resource plans evaluates the impact to utility earnings in the 5 and 10-year horizon of the plan and the impacts to credit ratings and the balance sheet. The evaluated financial items include incentives (i.e. EWR, contracts); recovery methods of remaining net book balances created by the accelerated retirement plan and their impacts to the credit rating and balance sheet; and projected earnings for incremental capital expenditures. Company witnesses Maddipati, Coker, and Watkins discuss these matters in the direct testimony presented by those witnesses.

Q. Please provide an overview of the Company's outreach efforts.

A. The Company conducted a stakeholder engagement process focused on three types of outreach methods tailored to the audience of each outreach method: (1) public outreach events, (2) technical workshops, and (3) collaboration with the local transmission owner and other stakeholders. Each outreach event was designed to provide transparency, education, and an opportunity to provide input to the IRP. These outreach events educated participants about the purposes and process of an IRP, and invited participants to share their ideas, suggestions, and opinions on meeting Michigan's future energy and capacity needs. Exhibit A-2 (RTB-2) details the Company's outreach efforts.

Q. Please describe the public outreach efforts.

A. For the public and the Company's customers, four virtual outreach session events were held, recorded, and posted to the Company's website for public consumption. The virtual outreaches were a four-part series focused on (1) Our Clean Energy Plan, (2) Road to Renewables, (3) Protecting the Planet, and (4) Smarter Energy Future. The virtual outreaches were widely promoted through press releases, customer outreach, owned media, social media, employee communications, and by the Company's State and Federal Governmental Affairs staff.

These outreaches were conducted in a virtual format due to the COVID-19 pandemic in 2020 and 2021. The Company's original intent had been to conduct in-person sessions across the state, and the Company's teams were required to quickly pivot to a virtual platform enabling customers and the public to engage with the Company while giving safety a top priority. To ensure participants and non-participating customers had a voice in the process, the Company initiated an online commenting section on its public website. This was initiated in July 2019 and continues to be an avenue today for customers to share their thoughts and questions. Details are shown in Exhibit A-2 (RTB-2).

Q. Please describe the technical workshops.

A. For those expected to be highly involved in the technical aspects of the IRP, a series of technical workshops were created to address questions and obtain detailed insights and requests that could be incorporated into the analytical portion of the IRP. The Company invited participants for these workshops based on the parties that participated in the Company's last electric rate cases and 2018 IRP case, Case No. U-20165. The first technical workshop session was held in-person on December 12, 2019 in Jackson, Michigan and virtual technical workshop sessions were held on May 28, 2020 and January 28, 2021. The technical workshops provided an opportunity for:

1) The Company to inform and educate stakeholders on the components of an IRP, the analytical approach, and preliminary results of the analysis of the IRP;
2) Stakeholders to ask the Company clarifying questions; and
3) The Company to solicit feedback from stakeholders, with documented comments for the Company to consider in the development of the IRP.

To facilitate these discussions, the technical workshops were led by the Company's communications experts, modeling experts, and leadership team. The three technical workshops followed the same basic format based on three one-hour segments.

The purpose and content of each technical workshop was as follows:

- Technical Workshop 1 (December 12, 2019): An initial kick off to develop this IRP. Content covered basic principles and objectives, new items being incorporated into the analysis, schedule, capacity position, and a preview of scenarios, sensitivities, and assumptions;

- Technical Workshop 2 (May 28, 2020): Shared specific information on the approach to public outreaches, a refresher on the IRP process, a refresh of scenarios and sensitivities being evaluated, major data assumptions, and approach to stochastics risk analysis; and

- Technical Workshop 3 (January 28, 2021): Shared progress to date on stakeholder outreach effort, a refresher of the IRP process, preliminary selection of resources in the analysis, description and approach to electric supply reliability, and approach to risk analysis.

Further details of the stakeholder engagement efforts put forth by the Company are in the Stakeholder Engagement Report in Exhibit A-2 (RTB-2).

Q. Please describe the collaboration efforts with the local transmission owner.

A. As part of the IRP development process, the Company engaged early on with the local transmission owner represented by METC/ITC to support evaluation of transmission system effects for cases of accelerated retirement, generation additions, network upgrade costs, and interconnection costs. The Company and METC/ITC met on a frequent basis to discuss the request for analysis, scope, assumptions, and deliverable dates. The analysis provided by METC/ITC was incorporated as part of the analysis to support the development of the PCA. Company witness Scott describes in more detail the collaboration efforts with METC/ITC.

Q. Please summarize the results of the stakeholder engagement report.

A. The outreach and engagement using virtual public outreach events, multiple technical workshops throughout the development of the IRP, and the engagement efforts with the local transmission owner were successful because they resulted in constructive discussions giving opportunity to consider different perspectives. Comments received during the virtual public outreach events focused on the need to transform to a cleaner resource mix sooner rather than later while continuing to be affordable and reliable.

Comments received from the technical workshops carried similar themes of the virtual public outreach questions and comments, but also included a focus on the content of the regulatory filing and providing an opportunity for the Company to perform and provide analysis on behalf of technical stakeholders. The analysis from METC/ITC provided insights and data on transmission effects and whether transmission alternatives were available to offer to the modeling analysis. Of the feedback received, the Company acted or responded to all comments. A report detailing the Company's public outreach efforts is provided as part of the Company's IRP Report, Exhibit A-2 (RTB-2).

Q. Please describe how the Company used the analysis and outcomes of each component identified in the IRP process.

A. Once the above analysis was complete, the results were reviewed from the perspective of reasonableness in assumptions and alignment with principles and objectives. The resulting portfolio of resources became the PCA. The PCA was evaluated through all scenarios and sensitivities to understand its performance under all study conditions and was measured against an Alternate Plan that represents a refreshed version of the 2018 IRP for affordability, electric supply reliability, reduction to environmental impacts, and resiliency to risk parameters to ensure the PCA represented a better IRP for Michigan.

Q. Please provide an overview of the scenarios and sensitivities presented in this IRP.

A. The IRP is based on modeling scenarios—future outlooks—to account for a range of potential outcomes for a study period of 2020 through 2040 to evaluate a 5, 10, 15, and 20-year time horizon consistent with Section 6t and the Commission's filing parameters approved in Case No. U-15896, et al. Various sensitivities—changes in key assumptions that are varied one parameter at a time within any given scenario—were then applied to account for uncertainties in the scenarios themselves. Modeling several scenarios and sensitivities provides a representation of external factors that could influence resource availability and selection, while seeking the most reliable, efficient, and economic results. By developing and studying several scenarios and sensitivities, the Company minimized the risk of focusing on a single outcome.

The process used to develop the IRP was rigorous and comprehensive, consistent with good utility practice, followed all Commission requirements, and balanced across People, Planet, and Prosperity to identify the most reasonable, prudent, and cost-effective plan to serve customers in a reliable manner.

Q. Please summarize the actual scenarios and sensitivities considered in this IRP.

A. This IRP includes four scenarios required by the MPSC: (i) Business As Usual (“BAU”)—(current conditions continue into the future); (ii) Emerging Technology (“ET”)—(current conditions continue except renewable resources, EWR, and DR become materially less expensive); (iii) Environmental Policy (“EP”)—(30% reduction in carbon by 2030 and materially less expensive renewable resources); (iv) Carbon Reduction—(replica of the required EP scenario at 1.5% year-over-year load growth with the Company’s PCA forced into that scenario, optimized and then evaluated for achieving a 28% and 32% reduction in carbon emissions from 2005 by 2025). In addition to these four scenarios, there were a collection of sensitivities required to be evaluated on each scenario. The Company’s scenarios and sensitivities are aligned with the scenarios and sensitivities mandated by the Commission’s November 21, 2017 Order in Case No. U-

18418. The Commission later included the Carbon Reduction scenario in the IRP scenarios and sensitivities in its February 18, 2021 Order in Case No. U-20633.

The Company modeled four additional scenarios, three of which mirror the scenarios mandated by the Commission in 2017. The Company replicated the BAU, EP, and ET scenarios mandated by the MPSC except for the base gas price forecast, the potential for DR programs, and the potential for EWR savings.

The Company created a fourth scenario, Advanced Technologies, to evaluate a future world with higher electric vehicle penetration offset by growing behind the meter generation and transformational EWR levels, resulting in flat to declining load over the 20-year time horizon.

In support of these scenarios and sensitivities, assumptions necessary to translate the scenarios and sensitivities into models were developed. This included assumptions such as, but not limited to, customer demand forecasts, fuel cost forecasts, technology characteristics and costs, and program levels for EWR and DR. The Company also performed screening evaluation producing a set of resource options for consideration in portfolio optimization analysis. The scenarios, sensitivities, assumptions, and modeling approach are discussed in detail in the direct testimony of Company witness Walz.

Q. What factors were considered in the accelerated retirement of fossil generation?

A. Factors considered in the accelerated retirement of fossil generation are the same considerations given to a resource plan. The Company utilized the framework described and shown above in Figure 3.

Q. Does the Company's modeling and analysis effort represent a robust foundation for the IRP?

A. Yes. The modeling and analysis efforts represent a robust foundation across the variables impacting People, Planet, and Prosperity over 116 combinations of scenarios and sensitivities. In total, there were 880 model runs equating to roughly 3,500 hours and computational runs measuring 440 working days (8 hours) or approximately 150 full days (24 hours) and storage space upwards of 10 Terabyte. In addition to the optimal plans generated from these scenarios and sensitivities a set of analysis was also conducted for the environment, rates, financials, community and employee impacts, and risk assessments. Figure 3 and the description above depicts the level of robust analysis used to develop the IRP and the resulting PCA.

Q. Please describe how the PCA was developed.

A. The PCA was developed as a refresh to the currently approved IRP and the results of modeling and analysis as described above in Figure 3. The Company identified the demand-side management and supply resources most widely selected by the Company's Aurora software across the scenarios and sensitivities. Based upon the resource plan generated by the BAU identifying natural gas units as an economic selection for customers in the near term, the Company conducted an RFP for existing gas units easily transferrable to Zone 7 or in Zone 7. The RFP was administered by an independent third party, Charles River Associates ("CRA"). This RFP process is further discussed by Company witness Troyer. The Company then examined the resource plans with and without the inclusion of CRA's RFP results to determine the reasonableness of the assumptions upon which they were based. Furthermore, the Company examined these resources to determine if they aligned with the planning objectives. Resources based upon reasonable assumptions and alignment with the planning objectives were included in the PCA in amounts necessary to meet capacity and energy needs.

Q. Please provide a summary of how the integration of transmission planning, distribution planning, and supply planning is represented in this IRP.

A. This IRP is an improved step toward integrating transmission, distribution, and supply planning to create a better plan for Michigan. The Company has worked with the local transmission owner over the past year and a half to support a level of analysis of certain resource plans generated from accelerated retirement of Company assets. This is evidenced by direct testimony and exhibits sponsored by Company witnesses Scott and Walz. The Company worked with distribution planners and engineers to design proxy units for solar and batteries including distribution-level value and benefits, and network upgrade and interconnection costs at the distribution level (46kV and below) as evidenced in the direct testimony of Company witnesses Scott, Battaglia, and Washburn. Lastly, the Company has filed, in conjunction with this IRP, a 5 and 10-year Electric Distribution Infrastructure Investment Plan ("EDIIP") that is aligned and supportive of the investments necessary to provide clean, reliable, affordable, and sustainable resources safely. The Company is well positioned to collaborate with the many departments and work necessary to create the best plans to serve Michigan's electric needs.

Q. Please identify the modeling consultants retained by the Company to perform independent reviews of the Company's IRP modeling and analysis.

A. The Company retained Siemens to perform an independent review of the IRP analysis and adherence with filing requirements. Siemens worked with Company experts to perform a thorough review of the approach undertaken to perform the IRP analysis. This included a detailed review of the methods and tools used, input assumptions, and adherence to filing requirements. Siemens' conclusion was that the IRP was prudent, appropriate, and aligned with all regulatory requirements. Siemens further concluded that the PCA is supported by a sound analysis and which appropriately considered alternate options and uncertainties.

SECTION IV: IRP BASELINE CAPACITY POSITION

Q. How does the Company currently meet the capacity and energy needs of its customers?

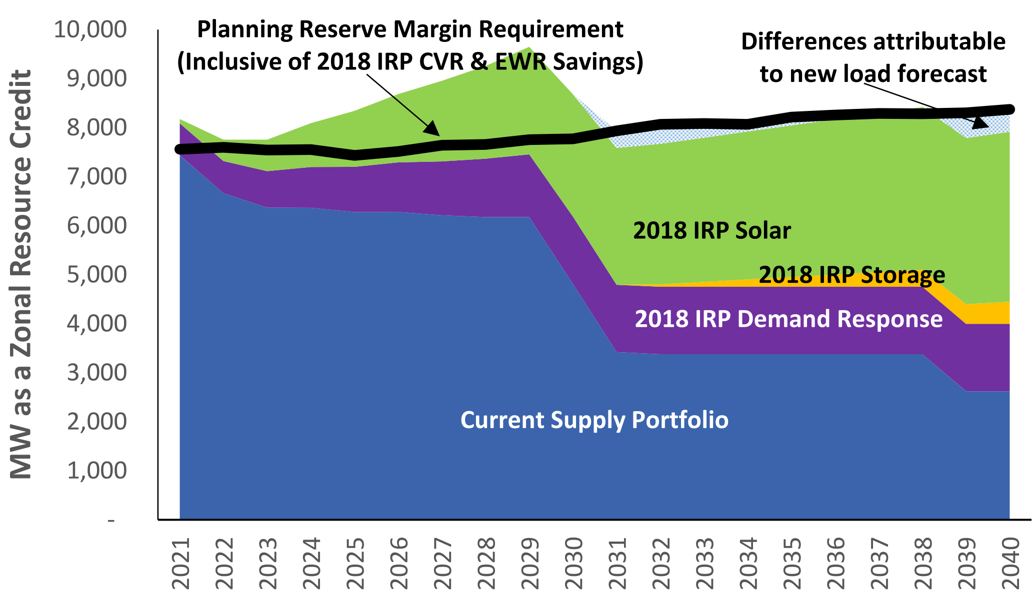
A. The Company meets the capacity and energy needs of its customers pursuant to its currently approved IRP, as described above. The Company's approved IRP provides energy and capacity through a diverse mix of demand and supply-side resources.

The Company currently owns 5,945 MW of installed capacity located within Michigan and within MISO Zone 7. Supply-side resources owned and operated by the Company include five coal-fueled generating units, two gas-fueled combined cycle plants, a pumped storage plant, several gas-fueled combustion turbines, two gas/oil-fueled steam turbines, 13 hydroelectric plants, four wind farms, and three solar plants. These generators are detailed in the direct testimony of Company witnesses Walz, Hatcher, and Kapala.

The Company also has contractual rights through PPAs to capacity from 118 counterparties totaling 3,793.3 MWs that are fueled in a variety of ways, including gas, coal, biomass, wind, water, and other renewable sources. Additionally, the Company has contracts in place with eight counterparties for energy and 379 contracts in place for the Experimental Advanced Renewable Program – Solar. These PPAs are addressed in more detail in the direct testimony of Company witness Troyer.

The Company's capacity position in March 2020, used as a basis to develop the baseline capacity position of this IRP, is shown in Figure 4 below and contains the major resources identified above in my direct testimony. It is important to note that the Company's capacity position outlook does not show a need for capacity through the 3, 5, and 20-year outlooks. The Company's capacity position is consistent with what was reported in the Company's capacity demonstration filing (Case No. U-20590) and the Company's commitment to acquire solar resources through annual competitive solicitations, as evidenced by 2019 and 2020 RFPs issued for new solar resources.

Figure 4: Base Case Balance of Supply and Demand to Meet PRMR



With the above stated, the Company did ultimately identify a discrete capacity resource solution based upon the retirement, electric supply reliability, risk, environmental, financial, and rate analysis conducted. This combined analysis indicating the potential to generate customer savings with the accelerated retirement of existing coal and oil/gas peaking units and the purchase of existing gas units will enable the Company to be cleaner faster while ensuring long-term electric supply reliability and reducing energy market purchase volatility present in the Company's first IRP. As described in the direct testimony of Company witness Walz, the addition of incremental amounts of batteries or solar resources as part of the electric supply reliability analysis did not adequately address the need for energy and capacity during all seasons of the year and based upon economic analysis, batteries were determined to not yet be economic when compared to other resources within the next decade. Additionally, as discussed by Company witness Battaglia, the development of an additional 5,500 MW of solar by the year 2025 to fulfill the replacement of capacity of Campbell Units 1, 2, and 3 and Karn Units 3 and 4 poses significant execution risks to safely interconnect, construct, and commence operations of these assets. To date, the Company has experienced timeframes between three to four years to develop solar assets that are at the upper end of projected price forecasts. The RFP issued on January 6, 2021 was tailored to existing gas resources in Zone 7, or easily transferrable to Zone 7, to solve the need for safe, reliable, affordable, and clean resources with minimal operational execution risks.

Q. What were the Company's base capacity outlooks at the onset of the IRP process?

A. The base capacity positions were developed for each scenario evaluated in the IRP. The base capacity position outlooks start from a spring of 2020 forecast of electric demand. The capacity position is defined as the total amount of planning resources in ZRCs less the total load forecast plus PRMR. The Company created four base capacity positions. A base capacity position was developed for the Company scenarios used for retirement analysis ("CE"), the MPSC required scenarios ("Annual Energy Outlook" or "AEO"), the

Company's Advanced Technologies scenario, and the MPSC-required Carbon Reduction scenario. The base capacity positions are further described in the direct testimony of Company witness Walz.

Q. Why were different base capacity positions created?

A. The Company created different base capacity positions to: (i) validate that the Company's approved 2018 IRP continued to be the most reasonable and prudent plan for its customers and Michigan by removing all resources not officially approved and/or the resources which have a greater level of uncertainty due to the length of time between current day and future state, and (ii) adjust the load forecast based upon levels of potential EWR savings that vary between scenarios.

Q. Please describe how the Company created a base capacity outlook to refresh the Company's currently approved IRP.

A. The Company's base capacity outlook included the following assumptions and adjustments:

- 1,100 MW (550 ZRCs) of solar generation made operational by 2024 (300 MW in 2022, 300 MW in 2023, and 500 MW in 2024) as part of the Company's approved IRP in Case No. U-20165 which has been or is being acquired through the Company's annual competitive solicitation process, as described in the direct testimony of Company witness Troyer. Planned solar acquisitions incremental to these levels were removed in years 2025 through 2040;

- DR at levels pre-approved in Case No. U-20165 for the period June 2020 through June 2022, as detailed in the direct testimony of Company witness McGraw. 2019 levels were also approved in the Company's 2018 electric rate case, Case No. U-20134. Planned DR incremental to these levels were removed in years 2023 through 2040;

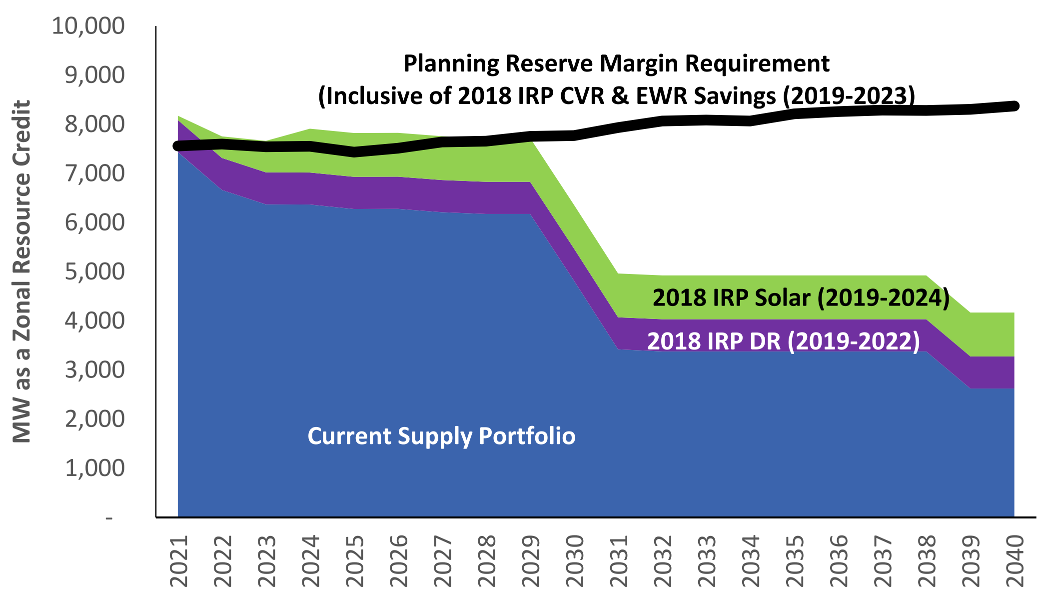
- EWR at levels pre-approved in Case No. U-20165 for the period June 2019 through June 2023, consistent with the Company's Biennial EWR plan Case No. U-20372, as detailed in the direct testimony of Company witness McLean. Planned EWR incremental to these levels were removed in years 2024 through 2040 and adjusted to reflect a 1% annual savings base for CE scenarios and a 1.5% annual savings base for MPSC-required scenarios (AEO);

- CVR program at levels pre-approved in Case No. U-20165 for the period June 2019 through June 2022, as detailed in the direct testimony of Company witness Henry. Planned CVR incremental to these levels were incorporated into the load forecast from 2023 through 2040; and

- 584 MW (292 ZRCs) addition of PURPA capacity made to be operational by May 31, 2024, as settled in Case No. U-20615.

Figure 5 provides the CE scenarios base capacity outlook to illustrate the Company's approach to creating a capacity shortfall that does not exist today because of the currently approved 2018 IRP. Additional outlooks are described in the direct testimony of Company witness Walz.

<u>Figure 5: Modified Base Case Balance of Supply and Demand to Meet PRMR</u>



Other major resources included in the baseline capacity position outlook are:

- Operation of Karn Units 1 and 2 through May 31, 2023;

- Operation of Karn Units 3 and 4 through their design lives (May 31, 2031);

- Operation of Campbell Units 1 and 2 through their design lives (May 31, 2031);

- Operation of Campbell Unit 3 through its design life (December 31, 2039);
- Zeeland and Jackson plants extend their design lives beyond 2040;
- 856 MW (139 ZRCs) of wind generation made operational as of 2021 as part of the Company's REP (Case No. U-18231);
- 100 MW (50 ZRCs) of contracted solar generation to be operational in 2021 as part of the Company's REP (Case No. U-18231);
- PPA with MCV continues to May 31, 2030; and
- PPA with Palisades to be terminated on May 31, 2022.

Q. Please describe the reason for major changes in capacity position through the 20-year plan.

A. The Company expects the retirement of multiple Company-owned generating resources and the expiration of contracted generating resources in the years 2030, 2031, and 2039. The MCV PPA for 1,240 MW (1,214 ZRCs) is set to expire on May 31, 2030. This contract does not contain a unilateral right to extend beyond 2030 and therefore the Company is not projecting an extension of this contract. Karn Units 3 and 4 are 1,120 MW (769 ZRCs) in size and are expected to retire in 2031, based on the design lives of those units. Campbell Units 1 and 2 are 260 MW (252 ZRCs) and 348 MW (337 ZRCs), respectively, and are expected to retire in 2031, based on the design lives of those units. Campbell Unit 3 is 785 MW (757 ZRCs) in size (excludes ~7% of capacity owned by other entities) and expected to retire in 2039, based on the design life of the unit. In total, the Company would need to replace approximately 3,300 ZRCs by 2040 to serve the projected peak demand plus reserve margins in that year.

SECTION V: PROPOSED COURSE OF ACTION

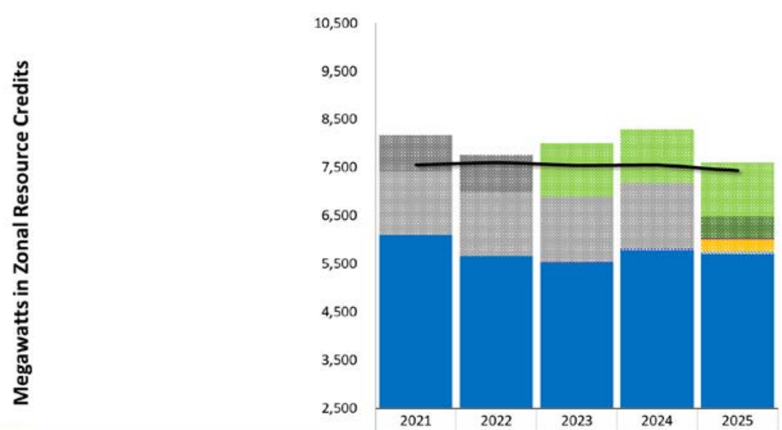
Q. Please describe the components of the Company's PCA.

A. The Company's PCA includes 5, 10, 15, and 20-year plans. The specific aspects of each portion of the PCA is described in detail below.

Q. Please provide an overview five-year plan.

A. The five-year plan accelerates the retirement of Campbell Units 1, 2, and 3 and Karn Units 3 and 4 and relies on incremental investment in DR, EWR, CVR, solar, and the purchase of existing gas units. The levels of the demand-side management programs are consistent with the Company's Biennial EWR plan Case No. U-20372 and the Company's recently filed electric rate case, Case No. U-20963. Figure 6 shows the incremental capacity of resources to the base capacity position described above and shown in Figure 5.

Figure 6: Proposed Course of Action 5-year Capacity Plan



	2021	2022	2023	2024	2025
Covert	-	-	1,114	1,114	1,114
DIG, Kalamazoo, Livingston	-	-	-	-	451
Karn 3&4	767	769	-	-	-
Campbell 1-3	1,313	1,318	1,344	1,346	-
New storage	-	-	-	-	
New Demand Response	-	-	12	25	37
New solar	-	-	-	-	250
New Energy Waste Reduction	-	-	-	20	57
Current Existing Portfolio	6,095	5,667	5,533	5,781	5,694
Planning Reserve Margin Requirements (Load +Margin)	7,558	7,600	7,542	7,553	7,435
	617	154	462	732	167

- EWR and CVR
  - 2023 and 2025 – (i) annual energy efficiency savings for EWR near 1.7% and (ii) incremental growth of CVR to 26.64 MW in 2025 bringing the total level of CVR to 56.81 MW;
- DR
  - 2023 thru 2025 DR programs continue to expand each year from the pre-approved levels in the base capacity outlook, adding an incremental capacity of 34 MW (37 ZRCs) in 2025 bringing the total level of DR to 641 MW (657 ZRCs) in 2025;
- Solar
  - 2025 – incremental 500 MW (250 ZRCs) increasing the total solar by 2025 to 2,284 MW (1,142 ZRCs);
- Karn Units 3 and 4 (oil and gas units)
  - 2023 – accelerated retirement of both units from their current design lives of 2031. These units are to retire with the Karn Units 1 and 2 coal units which are also scheduled to retire in 2023, pursuant to the Company's approved 2018 IRP. The MW capacity replacement for Karn Units 3 and 4 is 1,120 MW (787 ZRCs) by 2023;
- Covert (existing gas resource operating in Michigan)
  - 2023 – purchase of the existing gas resource, Covert, providing 1,176 MW (1,114 ZRCs) with an assumption to retire May 31, 2040; however the Company will determine the retirement date in future IRP filings;
- Campbell Units 1, 2, and 3 (coal)
  - 2025 – accelerated retirement of the three coal units at the Campbell Generating Complex. The current design lives of Campbell Units 1 and 2 is 2031 and the current design life of Campbell Unit 3 is 2039. The MW capacity replacement for Campbell Units 1, 2, and 3 is 1,393 MW (1,346 ZRCs) in 2025;
- DIG, Kalamazoo, and Livingston plants (gas)
  - 2025 – purchase of the DIG, Kalamazoo, and Livingston plants providing a total available capacity of 977 MW (770 MW for the DIG Plant, 75 MW for the Kalamazoo Plant, and 132 MW from the Livingston Plant). These MW levels equate to 912 ZRCs (728 ZRCs for the DIG Plant, 70 ZRCs for the Kalamazoo Plant, and 114 ZRCs from the Livingston Plant).

These units are assumed to retire May 31, 2040; however, the Company will determine the retirement date in future IRP filings; and

- Storage:
  - No storage additions for the purpose of meeting energy and capacity needs are planned in the five-year plan. The Company has initiated a set of learning opportunities each year from 2019 to 2024 that are described in the Company's EDIIP, to continue to improve the understanding of its viability and value. The economic selection of batteries remains challenged, as further described in the direct testimony of Company witnesses Walz and Washburn.

Q. Will the Company revisit the economic selection of batteries in future IRPs?

A. Yes. In future IRPs, the Company will continue to evaluate the resources which best meet the planning objectives of the Company and the Commission. To that end, the Company will continue to evaluate the role that batteries can play in the Company's resource portfolio, as it would for any resource type in its plan. As explained in the description of the Company's 10-year plan, the Company's PCA includes the addition of new storage resources in 2030. In future IRPs, there remains a possibility that storage resources could play a larger role in the Company's near-term plans if those resources become more economic.

Q. Please describe the Covert Plant which the Company proposes to purchase as part of the five-year plan.

A. As indicated above, the Company proposes to purchase the Covert Plant in 2023. The Covert Plant is a combined cycle natural gas-fired electric generating plant commissioned in 2004 with a nameplate capacity of 1,176 MW which is located in Covert, Michigan. The Covert Plant is currently operating in Michigan as a market participant in the PJM regional transmission organization. However, the Covert Plant originally operated in the MISO regional transmission organization. The transmission facilities needed to allow operation as a MISO market participant are this in place. Upon the purchase of the Covert Plant by the Company, the Covert Plant would transfer from PJM to MISO Zone 7 providing an additional 1,114 ZRCs of capacity and reliability to the Company's customers and Michigan.

The proposed acquisition of the Covert Plant is the result of a January 2021 RFP for existing gas resources, as described in the direct testimony of Company witness Troyer. The Company has signed a Purchase Sale Agreement ("PSA") to take full ownership of the Covert Plant on or about May 31, 2023 and the total purchase costs are $815 million. The PSA for the Covert Plant is addressed in the direct testimony of Company witness Battaglia.

As more fully explained in the direct testimony of Company witness Battaglia, which describes the design of the Covert Plant, the Covert Plant is designed to take advantage of rapid-changing load and market conditions. The Covert Plant has three mostly independent combined cycle units and each of those units has its own heat recovery steam generator with supplemental duct firing. The Covert Plant's availability has routinely averaged above 89% for the past five years. As explained in the direct testimony of Company witnesses Battaglia and Breining, the individual units of the Covert Plant are equipped with Selective Catalytic Reduction and Carbon Monoxide catalyst technology to control emissions within the approved air permit for the facility. Furthermore, as explained in the direct testimony of Company witness Gallaway, who describes the fuel supply arrangements of the Covert Plant, the Covert Plant receives natural gas fuel from the ANR Pipeline Company system.

In addition to the above, the Company is providing extensive detail in this filing as to the costs to operate the Covert Plant. The projected annual operating costs are approximately $219 million, including property taxes and environmental expenses, which are addressed by Company witnesses Walz, Kapala, Breining, and Kvoriak. Moreover, Company witness Coker provides the expected revenue requirements of the Covert Plant. Since the Company is requesting cost approval of the Covert Plant acquisition in this proceeding, the Company has met the Commission's IRP filing requirements for supply-side resource cost approval.

Q. Please the describe the DIG, Kalamazoo, and Livingston plants which the Company proposes to purchase as part of the five-year plan.

A. As indicated above, the Company proposes to purchase the DIG, Kalamazoo, and Livingston plants in 2025. The proposed acquisition of the DIG, Kalamazoo, and Livingston plants is the result of a January 2021 RFP for existing gas resources, as described in the direct testimony of Company witness Troyer. The Company has a fully executed PSA to take full ownership of the DIG, Kalamazoo, and Livingston plants on or about May 31, 2025 and the total purchase costs are assumed to be $530 million. The PSA for the DIG, Kalamazoo, and Livingston plants is addressed in the direct testimony of Company witness Battaglia.

As explained in the direct testimony of Company witness Battaglia, the DIG Plant is a combined cycle natural gas-fired electric generating plant commissioned in 2001 (includes a 160 MW simple cycle natural gas-fired generating unit in 1999) with a nominal nameplate capacity of 770 MW located in Dearborn, Michigan. The DIG Plant is currently operating in Michigan as a market participant in MISO. DIG also has three natural gas/blast furnace gas boilers that are partially fired with waste gas from AK Steel, an industrial company located adjacent to the DIG Plant. The DIG Plant has three gas turbines with two of the turbines operating in a combined cycle mode with a single steam turbine. The DIG Plant's availability has averaged 90% for the past three years. Furthermore, as explained in the direct testimony of Company witness Gallaway, who discusses the fuel supply arrangements for the DIG Plant, the site receives natural gas fuel from DTE Gas Company.

Company witness Battaglia also describes the design of the Kalamazoo and Livingston plants in his direct testimony. The Kalamazoo Plant is a simple cycle natural gas-fired electric generator with a nameplate capacity of 75 MW and was commissioned in 1999. The plant is in Comstock, Michigan. The Kalamazoo Plant has one gas turbine operating in a simple cycle mode with a single steam turbine. The plant's availability has averaged 92% for the past three years. As explained in the direct testimony of Company witness Gallaway, the Kalamazoo Plant receives natural gas fuel from the Panhandle Eastern Pipeline Company LP.

The Livingston Plant is a simple cycle natural gas-fired electric generator with a nameplate capacity of 156 MW and was commissioned in 1999. The plant is in Gaylord, Michigan. The Livingston Plant has four gas turbines operating in a simple cycle mode. The Livingston Plant's availability has averaged 96% for the past three years. As explained in the direct testimony of Company witness Gallaway, the Livingston Plant receives natural gas fuel from the DTE Gas Company and details of the fuel contracts can be found in Company witness Gallaway's direct testimony.

The availability of capacity from the DIG, Kalamazoo, and Livingston plants dedicated to serve the Company's peak demand plus PRMR is reflective of unsold capacity to other entities. The available unsold capacity is 451 ZRCs and steadily increases throughout the remainder of the study horizon. While a portion of the capacity has been sold to other entities, as explained in the direct testimony of Company witness Troyer, the Company's customers will benefit from the revenue of those sales or remain harmless because of the capacity surplus in the Company's capacity position.

In addition to the above, the Company is providing extensive detail in this filing as to the costs to operate the DIG, Kalamazoo, and Livingston plants. The projected annual operating costs are approximately $123.5 million, including property taxes and environmental expenses. The Company is expecting to receive revenues of approximately $12 million for steam sales annually and capacity and energy sales revenues of approximately $30 million (annually for the period 2025 to 2026) to approximately $3 million (annually beginning 2027 and going forward) annually. The projected annual operating costs and expected revenues are addressed by Company witnesses Troyer, Walz, Kapala, Breining, and Kvoriak. Moreover, Company witness Coker provides the expected revenue requirements of the DIG, Kalamazoo, and Livingston plants. In addition to the costs to purchase and operate the plants, the direct testimony of Company witnesses Battaglia and Troyer also describe the commodity sales contracts attributable to the DIG, Kalamazoo, and Livingston plants which the Company will assume after the acquisition of the plants and the proposed treatment of the revenues received by the Company through the commodity sales contracts.

Similar to the Covert Plant, since the Company is requesting cost approval of the acquisition of the DIG, Kalamazoo, and Livingston plants in this proceeding, the Company has met the Commission's IRP filing requirements for supply-side resource cost approval.

Q. What are the expected unit lifetimes of the Covert, DIG, Kalamazoo, and Livingston plants?

A. As set forth in Figure 1, the National Renewable Energy Laboratory's assumption for the life of a gas-fired unit is 55 years. However, as explained below in description of the 20-year plan, for simplicity in capacity expansion modeling, the Company is showing an assumed cease of operations of the Covert, DIG, Kalamazoo, and Livingston plants 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.

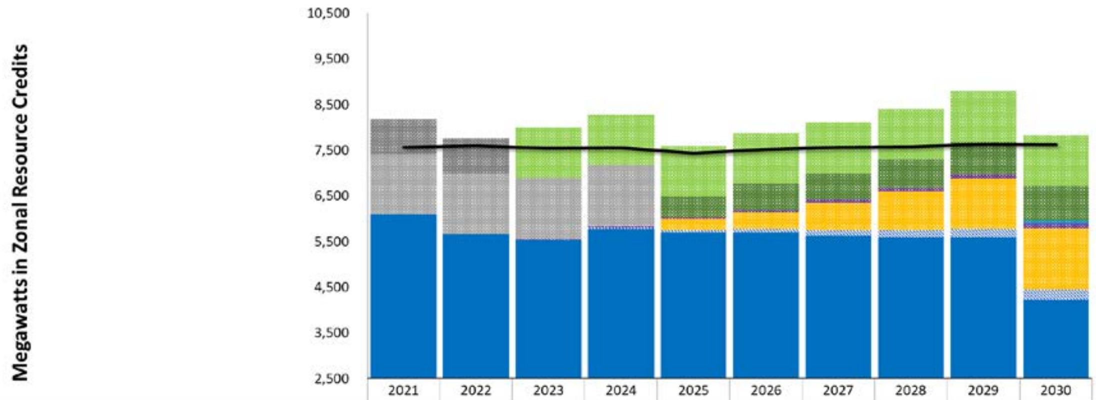
Q. Does the Company anticipate any potential socioeconomic impacts, such as employment, for the local regions of the to-be-purchased existing gas resources?

A. Since all of the aforementioned generating resources are currently in operation, the Company does not anticipate negative socioeconomic impacts related to the to-be-purchased existing gas resources. The Covert, DIG, Kalamazoo, and Livingston plants will need to continue to be staffed to adequately operate those resources and therefore, the plants will continue to provide employment opportunities for the local regions. Furthermore, as explained in the direct testimony of Company witness Kvoriak, in owning the Covert, DIG, Kalamazoo, and Livingston plants, the Company will be required to pay property taxes which will continue to provide tax revenues to the local regions.

Q. Please provide an overview of the 10-year plan.

A. The 10-year plan is a continuation of the five-year plan with sustained energy efficiency savings per year and continued expansion of solar, DR, and CVR. Starting in 2030, the Company introduces an ancillary services battery capable of 55 ZRCs (58 MW). The battery learning opportunities being planned for in the first five-year period of the IRP, as described in the direct testimony of Company witness Washburn, sets a deliberate annual plan to achieve operational readiness of batteries by 2030 or sooner to consistently and reliably serve customers peak and off-peak demand. The expansion of solar and demand-side management programs provides the Company with sufficient capacity for the expiration of the MCV contract in 2030. With the incremental addition of nearly 1,550 ZRCs of solar and batteries and nearly 400 ZRCs of incremental demand-side management programs, the Company is well positioned to meet the energy and capacity needs of customers at the time the MCV contract expires. Additionally, the purchase of the Covert Plant and DIG, Kalamazoo, and Livingston plants gives greater assurances of providing customers a cleaner, more affordable and reliable resource plan than the Company's currently approved IRP. The Company has planned to have an approximate 200 ZRC surplus in years of major transition versus planning to have a zero-capacity position in a year. The 200 ZRC surplus is added in years 2030 and 2031 in order to address execution risks of the planned incremental resources that exist in normal day-to-day electric utility operations. Figure 7 shows the incremental capacity of resources to the base capacity position described above.

<u>Figure 7: Proposed Course of Action – 10-Year Plan</u>



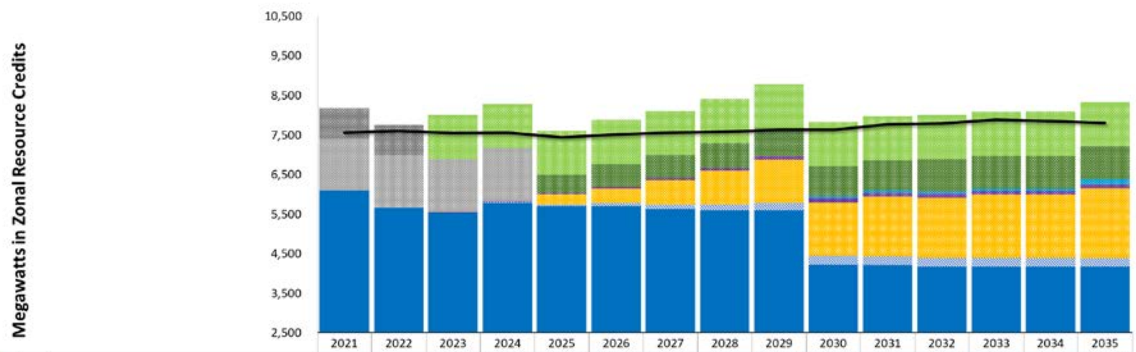
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Covert	-	-	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114
DIG, Kalamazoo, Livingston	-	-	-	-	451	579	579	619	711	767
Karn 3&4	767	769	-	-	-	-	-	-	-	-
Campbell 1-3	1,313	1,318	1,344	1,346	-	-	-	-	-	-
New storage	-	-	-	-						55
New Demand Response	-	-	12	25	37	49	62	74	87	98.9
New solar	-	-	-	-	250	352	602	852	1,102	1,352
New Energy Waste Reduction	-	-	-	20	57	91	123	157	187	216
Current Existing Portfolio	6,095	5,667	5,533	5,781	5,694	5,694	5,624	5,589	5,589	4,227
Planning Reserve Margin Requirements (Load +Margin)	7,558	7,600	7,542	7,553	7,435	7,516	7,558	7,575	7,627	7,625
	617	154	462	732	167	363	547	830	1,164	205

- EWR and CVR
    - o 2026 to 2030 – (i) annual energy efficiency savings for EWR remain near 1.7% and (ii) an incremental 56.31 MW of CVR to 113 MW in 2030;
- DR
    - o 2026 to 2030 DR programs continue to expand each year from the pre-approved levels in the base capacity outlook, adding an incremental capacity of 91 MW (99 ZRCs) in 2030 bringing the total level of DR to 698 MW (756 ZRCs) in 2030;
- Solar
    - o 2026 to 2030 – incremental 2,204 MW (1,102 ZRCs) increasing the total solar by 2030 to 4,488 MW (2,244 ZRCs); and
- Storage:
    - o 58 MW (55 ZRCs) of batteries is added in the year 2030. This amount represents one ancillary services market battery and is the beginning of a glide path of batteries to serve forecasted demand needs in the year 2040. Details about the battery are provided in the direct testimony of Company witnesses Walz, Battaglia, and Washburn.

Q. Please provide an overview of the 15-year plan.

A. The 15-year plan is a continuation of the 10-year plan with sustained levels of demand-side management programs, solar, and batteries. Beginning in the year 2035, the solar and battery glidepaths begin in preparation for replacing future capacity and energy needs in 2040. The Company applied the 200 ZRC capacity surplus in years 2031 to 2033 to address potential execution risks. Figure 8 shows the incremental capacity of resources to the base capacity position described above.

Figure 8: Proposed Course of Action – 15-year Plan



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Covert	-	-	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114
DIG, Kalamazoo, Livingston	-	-	-	-	451	579	579	619	711	767	767	817	828	828	828
Karn 3&4	767	769	-	-	-	-	-	-	-	-	-	-	-	-	-
Campbell 1-3	1,313	1,318	1,344	1,346	-	-	-	-	-	-	-	-	-	-	-
New storage	-	-	-	-						55	57	58	59	60	138
New Demand Response	-	-	12	25	37	49	62	74	87	98.9	99	99	99	99	99
New solar	-	-	-	-	250	352	602	852	1,102	1,352	1,498	1,513	1,591	1,591	1,759
New Energy Waste Reduction	-	-	-	20	57	91	123	157	187	216	232	232	229	229	225
Current Existing Portfolio	6,095	5,667	5,533	5,781	5,694	5,694	5,624	5,589	5,589	4,227	4,209	4,168	4,168	4,168	4,168
Planning Reserve Margin Requirements (Load +Margin)	7,558	7,600	7,542	7,553	7,435	7,516	7,558	7,575	7,627	7,625	7,770	7,796	7,883	7,844	7,807
	617	154	462	732	167	363	547	830	1,164	205	205	205	205	246	524

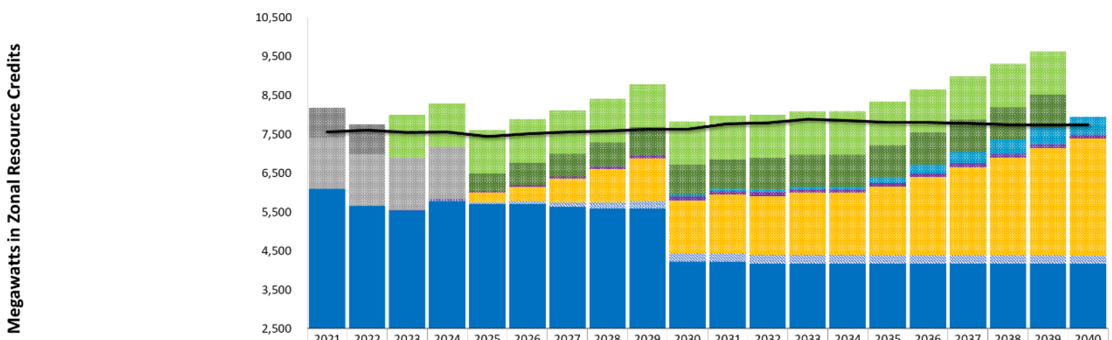
- EWR and CVR
  - o 2031 to 2035 – (i) annual energy efficiency savings for EWR at 1.9% by 2035 and (ii) no additional growth in CVR beyond levels identified in year 2030;
- DR
  - o 2031 to 2035 DR programs are at levels identified in year 2030. There is no additional growth in the DR program beyond year 2030;

- Solar
  - o 2031 to 2035 – reaches 3,518 MW (1,759 ZRCs) by 2035 increasing the total solar to 5,302 MW (2,651 ZRCs); and
- Storage:
  - o 2031 to 2035 – reaches (145 MW) 138 ZRCs of batteries by 2035. These batteries represent the additions of a distribution asset upgrade deferral battery and traditional energy and capacity batteries.

Q. Please provide an overview of the 20-year plan.

A. The 20-year plan is a continuation of the 15-year plan with an expansion of energy efficiency savings over 2% per year (2.1% in year 2040), solar, and batteries. Starting in 2035, the Company begins its second glidepath of solar reaching 6,018 MW (3,009 ZRCs) by 2040 and a glidepath of batteries reaching of 475 MW (450 ZRCs) by 2040. The expansion of solar and batteries, and the continued commitment to the levels of demand-side management programs, are the replacement technologies for the assumed retirement of 2,000 ZRCs of existing gas units. For simplicity in capacity expansion modeling, the Company is showing an assumed cease of operations of the Covert Plant and the DIG, Kalamazoo, and Livingston plants by May 31, 2040, however, 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. The Company remains committed to its Net Zero Carbon Emissions goal by 2040 and continues to be engaged and involved in partnerships with Electric Power Research Institute ("EPRI") on its carbon initiatives and other avenues. The Company's 200 ZRCs capacity surplus to address execution risks was applied to 2040. Figure 9 below shows the incremental capacity of resources to the base capacity position described above and shown in Figure 5. The Company's capacity position achieves a significant surplus in the late 2020s, and again in the late 2030s, as the Company builds its resource portfolio in preparation for the capacity losses from expiring or retiring supply resources. This surplus serves as a prudent hedge against potential execution and delivery risks with adding demand-side management programs and the significant levels of solar generation. The modular approach of adding smaller portions of supply on a yearly basis allows the Company to be flexible in its resource planning—providing the opportunity to evolve and adapt to changing conditions. Note that the Company's capacity position returns to near zero in years 2031 and 2040, indicating that the backfill plan provides sufficient capacity for the expiration of the MCV PPA as well as the generating assets that retire in 2031 and 2040.

<u>Figure 9: Proposed Course of Action – 20-year Plan</u>



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Covert	-	-	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	
DIG, Kalamazoo, Livingston	-	-	-	-	451	579	579	619	711	767	767	817	828	828	828	828	828	828	828	
Karn 3&4	767	769	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Campbell 1-3	1,313	1,318	1,344	1,346	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New storage	-	-	-	-						55	57	58	59	60	138	216	293	371	449	450
New Demand Response	-	-	12	25	37	49	62	74	87	98.9	99	99	99	99	99	99	99	99	99	99
New solar	-	-	-	-	250	352	602	852	1,102	1,352	1,498	1,513	1,591	1,591	1,759	2,009	2,259	2,509	2,759	3,009
New Energy Waste Reduction	-	-	-	20	57	91	123	157	187	216	232	232	229	229	225	222	220	218	215	213
Current Existing Portfolio	6,095	5,667	5,533	5,781	5,694	5,694	5,624	5,589	5,589	4,227	4,209	4,168	4,168	4,168	4,168	4,168	4,168	4,168	4,168	4,168
Planning Reserve Margin Requirements (Load +Margin)	7,558	7,600	7,542	7,553	7,435	7,516	7,558	7,575	7,627	7,625	7,770	7,796	7,883	7,844	7,807	7,804	7,785	7,745	7,734	7,739
	617	154	462	732	167	363	547	830	1,164	205	205	205	205	246	524	852	1,196	1,562	1,898	200

Q. Please provide a summary of the economic analysis of accelerating retirement of the Campbell and Karn operating units.

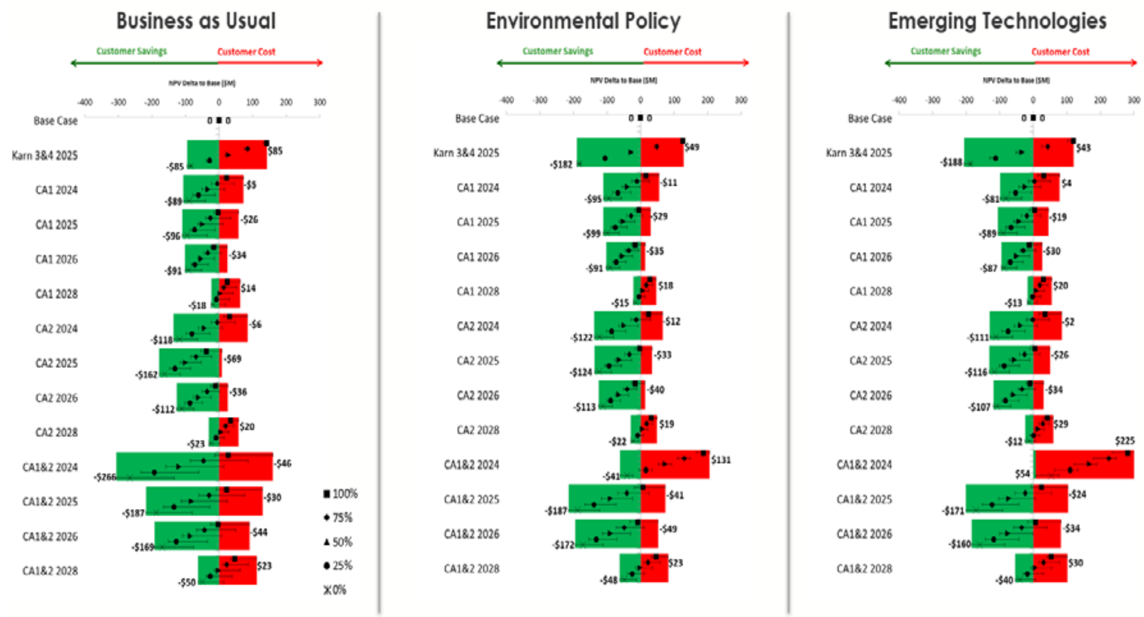
A. The Company used Aurora to first conduct a capacity expansion analysis to serve the capacity and energy needs of projected customer demand for: (i) continued operation of

Karn Units 3 and 4 and Campbell Units 1 and 2, versus (ii) the accelerated retirement of Karn Units 3 and 4 in years 2023 and 2025 and Campbell Units 1 and 2 in years 2024, 2025, 2026, and 2028 in isolation and together. Additionally, the Company evaluated each of the optimal replacement plans for these cases against the base continued operations case under a cost benefit analysis and an assessment using the other sets of analysis identified in the IRP process described and depicted in Figure 1 above.

The analysis re-examined the ongoing capital expenditures and O&M expenses necessary to continue operation of each of the units between now and the expected design lives. Additionally, ongoing capital expenditures and O&M expenses were analyzed for the accelerated retirement years designated in the 2018 IRP settlement agreement for Campbell Units 1 and 2, the retirement of Campbell Unit 3 in 2025, and Karn Units 3 and 4 retiring in 2023 and 2025. The above referenced capital expenditures and O&M expenses are detailed in the direct testimony and exhibits of Company witnesses Kapala and Breining.

The results of the analysis are summarized in Figure 10. The ranges of results depicted are created by evaluating the market benefits provided by the units against the cost of continued operation at various capacity and natural gas prices.

Figure 10: NPV Results of Retirement Analysis ($000,000)



Various gas prices were considered in the development of the range of the NPV of the incremental revenue requirement results. These natural gas prices are a function of the base gas price used for each scenario. The natural gas price used for the BAU CE, EP CE, and ET CE scenarios shown above is the Company's base case natural gas price forecast discussed in the direct testimony of Company witness Gallaway. The natural gas price forecast sensitivities were -25%, 0%, 25%, and 50% of the base natural gas price forecast. The range of each whisker bar represents the range of NPV values at the given cost of new entry ("CONE") price and the range of increasing/decreasing natural gas prices.

Various capacity prices were also considered and are a function of the MISO CONE. The capacity price sensitivities were 0%, 25%, 50%, 75%, and 100% of CONE and are identified by each marker in the figure above. The Company considers 75% of CONE to be the base case for market capacity prices. The Company's base capacity price forecast is discussed in the direct testimony of Company witness Walz.

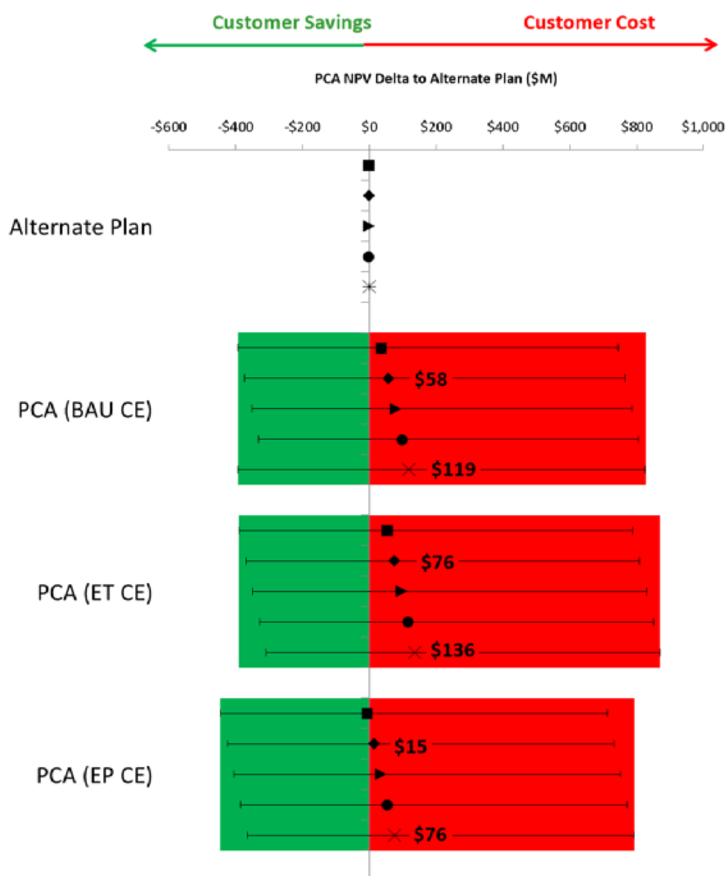
The results indicate that, under BAU CE assumptions, when the available replacement resources are considered, retiring and replacing Karn Units 3 and 4 in 2025 was determined to offer marginal customer savings of $85 million assuming 0% of CONE and $85 million in lost opportunity (i.e., customers will not receive the value of capacity) at 75% of CONE, assuming the Company's natural gas price forecast in both CONE assumptions. Under both CONE assumptions there is a potential for additional cost savings with minor impacts to the customers' lost opportunity of revenue across all three scenarios (BAU, ET, and EP).

The economic analysis of retiring Campbell Units 1 and 2 in isolation showed minimal changes in years 2024, 2025, and 2026. The units in isolation show improvement in economics if one of the units were retired prior to the year 2028 at which point environmental expenditures are no longer avoidable. Similar results occurred for the cases retiring both units in the same year. As seen in the Karn Units 3 and 4 analyses, improvements in economics with minimal changes in customer lost opportunity is seen across all scenarios. The environmental expenditures and non-environmental expenditures are further discussed in the direct testimony of Company witnesses Breining and Kapala, respectively.

Given the results of the economic analysis in combination with the electric supply reliability, customer rate impact, environmental impact, employee and community impact, and financial impact assessments, the Company found it compelling to pursue a plan retiring Karn Units 3 and 4 in 2023 with the already approved retirement of Karn Units 1 and 2 in 2023. The Company also found it compelling to pursue accelerated retirement of Campbell Units 1 and 2 together and consider the accelerated retirement of Campbell Unit 3.

The Company evaluated two options for accelerated retirements. One option is presented as the Alternate Plan and is an updated version of the Company's currently approved IRP that relies upon demand-side management programs, solar, and batteries to replace Karn Units 3 and 4 in 2025 versus 2023 because of execution risks identified with achieving the commercial operation dates of the solar and demand-side management programs, Campbell Units 1 and 2 retiring in 2031, Campbell Unit 3 retiring in 2039, and the MCV PPA expiring in 2030. Karn Units 3 and 4 retiring in 2025 is a "no regrets" decision and was incorporated into the Alternate Plan which is used to evaluate the PCA against a status quo approach. The PCA ceases operations of Karn Units 3 and 4 in the year 2023 and Campbell Units 1, 2, and 3 in 2025. These units are replaced with the purchase of existing gas units, continued expansion of demand-side management programs, and solar. The results of comparing the NPVs from the Alternate Plan versus the PCA are presented in Figure 11.

Figure 11: Alternate Plan versus PCA

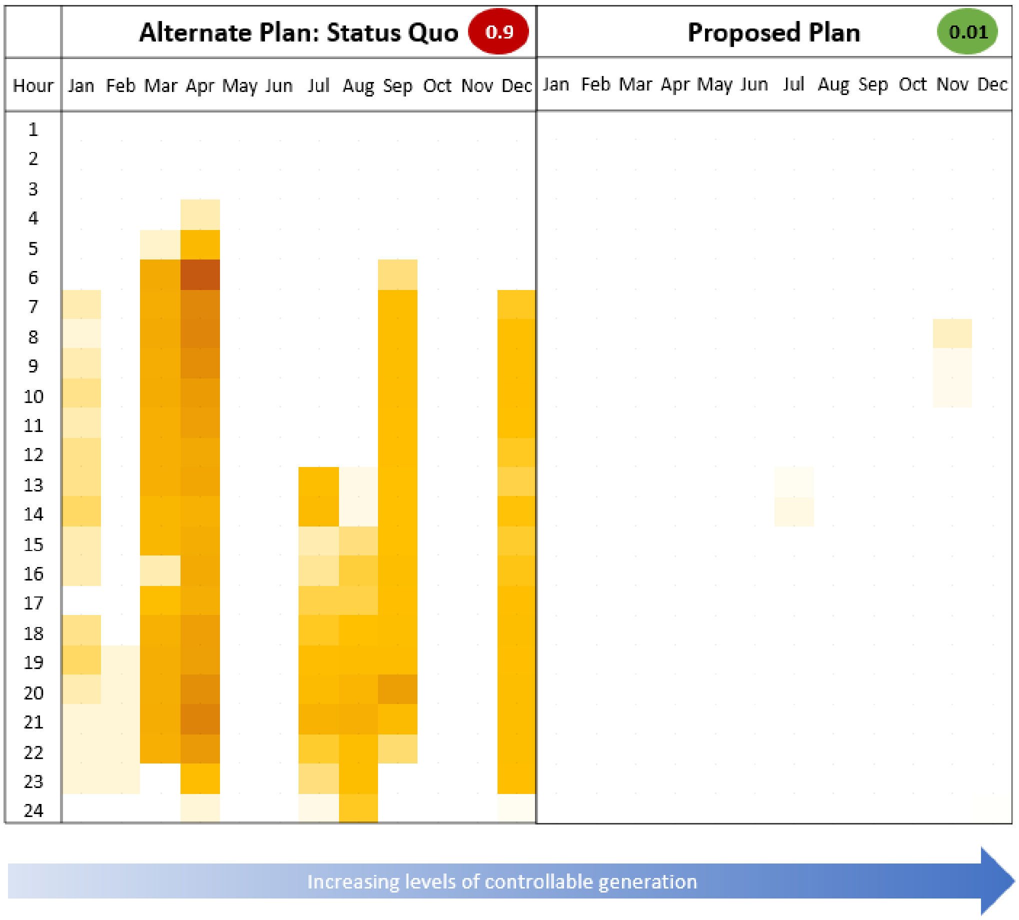


The economic analysis of the Alternate Plan versus the PCA indicates neutral to marginal modest customer cost/benefits using the assumed purchase costs of the Covert Plant and the DIG, Kalamazoo, and Livingston plants. This analysis, when combined with the customer rate impact, environmental impact, employee and community impact, and financial impacts, as discussed further in this direct testimony, shows it is most reasonable and prudent to purchase the Covert Plant in 2023 and the DIG, Kalamazoo, and Livingston plants in 2025, retire Karn Units 3 and 4 in 2023 with the already approved retirement of Karn Units 1 and 2 in 2023, and retire Campbell Units 1, 2, and 3 in 2025. The final decision on retirement will be made pursuant to regulatory approval of the purchase of the Covert Plant and the DIG, Kalamazoo, and Livingston plants, and the continued expansion of solar, batteries, and demand-side management programs in a manner similar to the 2018 IRP.

Q. Please provide a summary of the Company's electric supply reliability assessment results.

A. A capacity sufficiency assessment evaluated electric supply reliability concerns in the year 2032 to identify electric supply reliability issues. The year 2032 is used as a point in time when the Company makes a transformational change in its resource mix. This transformational change replaces nearly 3,500 MW of controllable generation with intermittent resources (i.e. 5,000 MW of solar) and demand-side management programs (nearly 2,000 MW of peak load reduction). This is 38% controllable generation owned by the Company replaced with intermittent and demand-side programs. The results of the assessment on the refreshed 2018 IRP case identified consecutive hours and days throughout the year, particularly in the winter, when the Company would not be sufficient in supplying customers with electricity, even when full access to 3,200 MW market purchases (i.e. the CIL) is available. These shifts are recognized by the industry, as indicated by MISO's efforts to change to a seasonal market construct and evaluating resource needs beyond a summer peak period. Furthermore, while the CIL is used as a resource fully available to Consumers Energy for modeling purposes – it is not. The day to day use of this resource up to 3,200 MW is not a reasonable or prudent solution to mitigating electric supply reliability issues and should not be used as resource to consistently serve customers every hour of every day throughout the year. Figure 12 illustrates a heat map of when the study identifies a frequency of not serving customer needs under a stress test of various parameters effecting reliability (i.e. generator availability, DR availability, load changes).

Figure 12: Capacity Sufficiency Assessment Heat Map of Intermittent versus Controllable Generation



The NERC standard for regional reliability is a probability that no less than 1 day in 10 years results in the loss of load. The study conducted by the Company determines an average LOLE of 1 day in 10 years to equate to the NERC standard. If a plan achieves an average LOLE of 0.1 or less the plan is sufficient in meeting capacity and energy needs. An average LOLE greater than 0.1 indicates deteriorating capacity sufficiency. The analysis clearly indicates improved reliability in all hours of the year with the use of controllable generation. Batteries were considered as a possible resource to meet times of deficiency in supply, however due to its short-lived charging and discharge cycles and the economic neutrality of the cost to charge to the value of discharging, batteries were not adequate in closing the reliability gaps across all hours and continue to draw on carbon emitting resources to charge which inhibits the ability to achieve reductions in carbon emissions for all sources of energy. The accelerated retirement of Campbell Unit 3 in the earlier 2030s or in 2025 would further exacerbate the reliability issues if the replacement plan is overly reliant on renewable/intermittent resources and demand-side management resources.

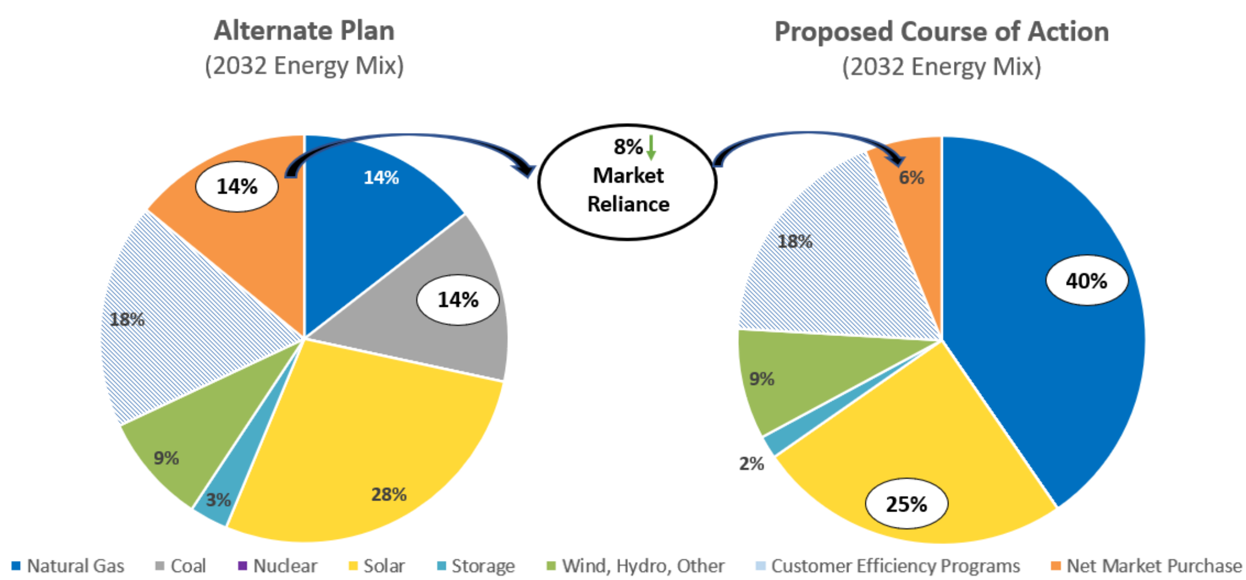
The capacity sufficiency assessment analysis, as discussed above, supported the Company's decision to issue an RFP for existing gas units to create a plan mitigating short- and long-term electric supply reliability concerns while achieving cleaner air emissions.

The resulting PCA compared to the base Alternate Plan clearly finds the Company's PCA to be superior in providing long-term capacity sufficiency in all seasons and in every hour of every day. Details on MISO constructs and system operability are discussed in the direct testimony of Company witness Clark and the capacity sufficiency assessment is discussed in detail in the direct testimony of Company witness Walz.

Q. Did the Company evaluate any additional factors in its electric supply reliability assessment?

A. Yes. As a part of the electric supply reliability assessment the Company evaluated the level of energy market reliance of the resource plan. In comparing the year 2032 of the Alternate Plan to the PCA, the Company found that the purchase of the existing gas units cut the energy market reliance by 50%. That reduces the Company's exposure to market price volatility and provides the Company with the ability to choose, in the best interest of customers, whether to economically dispatch the controllable generation or rely on economic energy from the market. The operational cycling capabilities of the Covert, DIG, Kalamazoo, and Livingston plants as gas units, versus coal units, enhances the Company's level of responsiveness to market signals related to dispatch of resources. Figure 13 is a comparison of the energy reliance between the Alternate Plan and the PCA. The direct testimony of Company witness Clark further discusses market reliance.

<u>Figure 13: Energy Mix for the Alternate Plan versus the PCA in the year 2032</u>

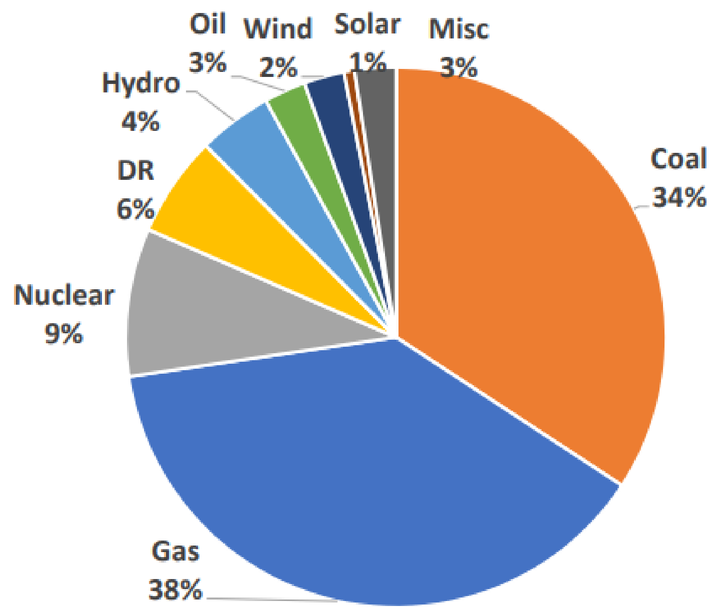


Lastly, a transmission analysis was conducted for the cases retiring Karn Units 3 and 4 in 2023, retiring Campbell Units 1 and 2 as early as 2024, and retirement of Karn Units 3 and 4 in 2023 with the retirement of Campbell Units 1, 2, and 3 in the year 2025 (reflective of the PCA). The transmission analysis was conducted by the local transmission owner METC/ITC. In summary, the transmission analysis did not indicate voltage issues but did identify thermal issues requiring transmission investments. These investments were converted by METC/ITC into a revenue requirement that is incorporated into the Company's NPV analysis for accelerated retirement cases and the PCA. The details of the analysis are described in the direct testimony of Company witness Scott.

Q. Please provide a summary of the Company's environmental impacts assessment results.

A. The environmental impact assessment for the accelerated retirement of Karn Units 3 and 4 and Campbell Units 1 and 2 showed positive impacts for carbon emissions reductions to further close the gap to achieve greater than 90% carbon reductions of the Company's owned generation resources and the Company's Net Zero Carbon Emissions for all sources. Whether the Company owns or purchases from the market makes zero to minimal changes in closing the gap to Net Zero Carbon Emissions. This is due to the need for market purchases to serve customer demand under a heavy renewable plan or to generate the energy for customers through traditional controllable generation. The purchase of the existing gas units helps to reduce the need for market purchases and in turn offsets potential carbon emissions being generated by coal resources in the market. As shown in Figure 14, the MISO market is made up of 34% coal and becomes a major source of energy to supply customers when renewable and demand-side resources are unavailable due to lack of sun, wind, and customer participation. Additionally, there were reductions in water, waste, and other air criteria pollutants identified with accelerated retirement of these units. The direct testimony of Company witness Breining further describes the results. Additionally, whether the Company purchased the Covert, DIG, Kalamazoo, and Livingston plants or not, these facilities exist and operate today and allow the Company to retire Campbell Units 1, 2, and 3, and Karn Units 3 and 4 early resulting in drastically reducing air emissions.

Figure 14: MISO Fuel Mix from MISO Planning Resource Auction for Planning Year 2020-2021 (MISO, 2020)[3]



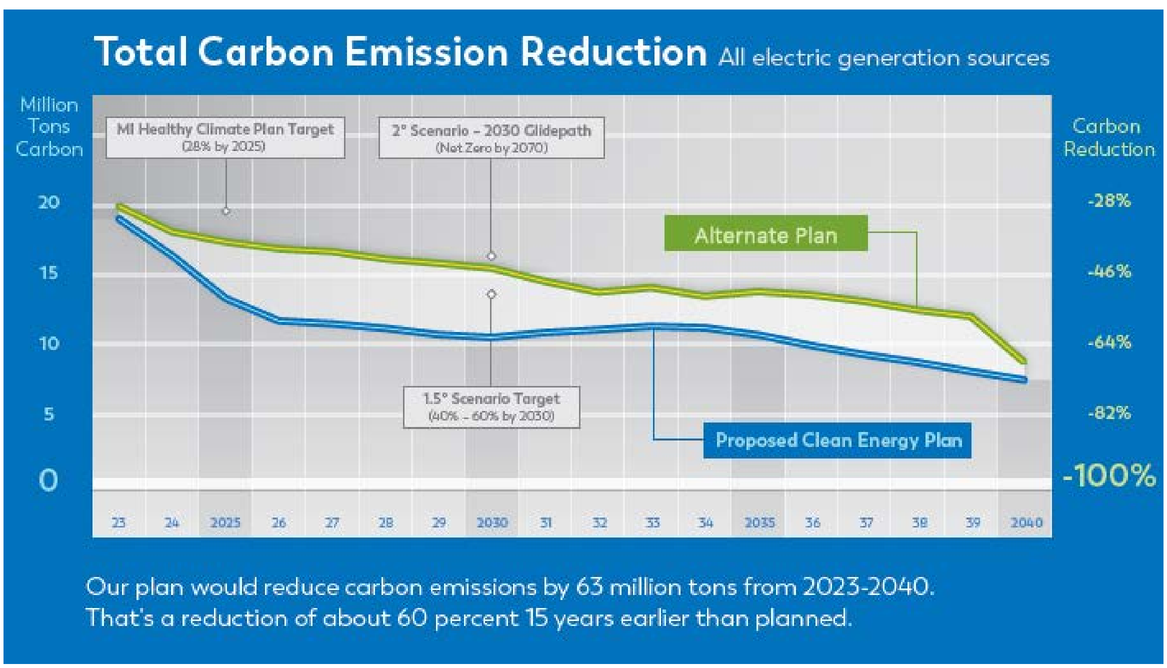
The Alternate Plan (status quo 2018 IRP) relies heavily on market purchases and continued investments in the coal units to allow for continued operations through 2039. The PCA reduces carbon emissions when compared to the Alternate Plan by 63 million tons, which is eliminating about 5.5 years of emissions, at the Company's current emission rates. Figure 15 depicts the carbon emissions between the Alternate Plan and the PCA that are generated to serve customer load in comparison to the goals discussed above. The emissions include Company-owned generation, PPAs, and net MISO market purchases. The direct testimony of Company witness Breining describes the calculation of all generating sources calculated and the resulting outcomes. The Company also

[3] MISO 2020/2021 Planning Resource Auction Results, April 14, 2020, page 11.

conducted an Environmental Justice assessment of the PCA, and it is further detailed by Company witness Breining.

To close the remaining carbon gap by 2040, future technology solutions will be necessary. To achieve Net Zero Carbon Emissions by 2040, the Company could cease operations or otherwise clean (via carbon capture and sequestration, or by burning hydrogen as a fuel) the exhaust of the Company's natural gas generating fleet, use carbon off-sets, or other technology solutions. Research, analysis, and collaboration with institutes, like EPRI and the Department of Energy, will be needed to identify reasonable and prudent measures for achieving these goals. The possible technology solutions and the barriers and opportunities of those solutions are further discussed in the direct testimony of Company witness Battaglia.

Figure 15: Carbon Emission Reductions of the PCA versus Alternate Plan (all generating sources)



Q. Please provide a summary of the Company's employee and community impacts assessment results.

A. The employee impact assessment for the accelerated retirement of Karn Units 3 and 4 identified approximately 80 employees impacted. The accelerated retirement of Campbell Units 1 and 2 impacts approximately 115 employees and is inclusive of all relevant organizations supporting the operations of the facilities. The accelerated retirement of Campbell Unit 3 impacts an additional 200 employees. The Company assessed the opportunities for re-skilling and retention packages that have been successful during prior retirements, such as those used in the accelerated retirement of the Classic 7 coal units (previously located at J.C. Weadock, B.C. Cobb, and J.R. Whiting sites). The Company remains committed to its employees and exercising the Company's cultural value of caring for co-workers during the transition and through the retirement of the plants. Company witness Kapala discusses this further.

The community impacts assessment for the accelerated retirement of Karn Units 3 and 4 identified an annual tax revenue loss of about $1.45M ($2022). The accelerated retirement of Campbell Units 1, 2, and 3 equates to a tax revenue loss of about $3.5 million ($2022). The Company identified community benefits with the full closure of the Karn and Campbell generating complexes because it would accelerate the ability for the community to fully re-develop those properties sooner to off-set the tax revenue loss rather than wait for a future retirement of one or two units left on the site. The Company is well positioned to provide the support to impacted communities by leveraging its successful history of supporting communities during the closure of the Classic 7 and the prepared work of retiring Karn Units 1 and 2.

Q. Does Consumers Energy have a process it follows to help ensure a Just Transition for communities impacted by the clean energy transition?

A. Consumers Energy has a process for Just Transition that involves four phases: (1) a commitment to fair and equitable treatment of impacted employees and communities; (2) gathering information through engagement with the community and stakeholders; (3) visualizing scenarios to implement; and (4) implementing solutions. Consumers Energy continues to be fully committed to community stakeholder collaboration and an orderly transition process at each of its remaining sites.

Q. Based on experience or any recent developments, is there anything Consumers Energy would adjust to enhance its approach to Just Transition as it implements the 2021 approved IRP (or PCA)?

A. The Company's plan is the continuation of a successful engagement process it's utilized since discussions began about decommissioning coal plants and seeking renewable development opportunities to ensure Michigan has safe, reliable, and affordable energy generation. The Company values the historic contributions of its facilities, the employees who work at the facilities, and the communities that host the facilities. The Company is determined to help those impacted by the accelerated plant retirements to navigate the changes positively, and the Company is looking forward to serving its customer communities for years to come.

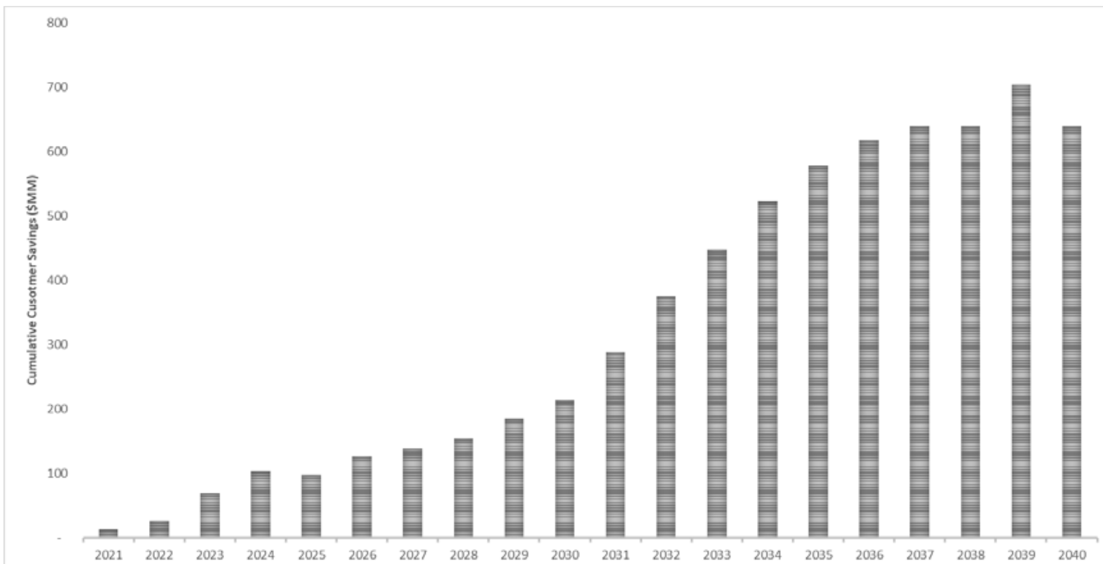
Through the Company's experience, Consumers Energy has learned that engaging its employees and communities as early as possible is critical for gathering information and developing solutions that work because these efforts take time. In addition, as the Company expands its reach through the 2021 IRP and continues to promote renewable energy, it is important that the Company looks for equitable opportunities to create clean energy jobs not only in communities where the Company is closing facilities but also for traditionally marginalized communities as well.

Q. Please provide a summary of the Company's customer rate impacts assessment results.

A. The customer rate impact assessment for the accelerated retirement of Karn Units 3 and 4 and Campbell Units 1 and 2 showed a potential for customer savings (NPV) for each accelerated retirement year across the CE scenarios assessed under a working assumption that the remaining net book balance would be recovered as a regulatory asset through the current design life of the unit. A reduction in the CAGR was identified for these cases as well, however, in times of retiring an asset, customers experience high year-over-year rate increases (i.e. highest 0.72%). In the development of the PCA, the rate impact associated with the accelerated retirement of Campbell Unit 3 was incorporated into the analysis comparing the Alternate Plan to the PCA. As discussed by Company witness Coker, the PCA shows an NPV decrease in the incremental revenue requirement of about \$300 million through 2040 and a cumulative savings of approximately \$640 million in 2040.

The Alternate Plan relies heavily on market purchases and continued investments in the coal units to allow for continued operations through 2039. The PCA will be more cost-effective for customers through the transformation of fleet and exit from coal. The addition of the DIG, Kalamazoo, and Livingston plants and the Covert Plant will add \$1.4 billion of rate base and will be collected from customers through 2040. While these units will add costs in the form of increased depreciation and return on capital, it will be more than offset by lower market purchase costs, lower O&M, and lower future capital spending associated with the coal units. Figure 16 shows the projected customer savings of the PCA versus the Alternate Plan. Additional details of the customer rate impact analysis are detailed further in Company witness Coker's direct testimony.

<u>Figure 16: Projected Cumulative Customer Savings – PCA versus Alternate Plan</u>



Q. Please provide a summary of the Company's financial impacts assessment results.

A. The financial impacts assessment used the working assumption of recovering the remaining unrecovered net book balances of Karn Units 3 and 4 and Campbell Units 1, 2, and 3 as a regulatory asset recovered through the units' current design lives. The resulting financial impact was neutral to minimal changes to the earnings per share in all cases. However, this would not be the case if the Company was not able to recover the remaining unrecovered net book value as a regulatory asset. The direct testimony of Company witness Maddipati discusses this issue further.

Q. Please provide a summary of the planning objectives and analysis that led to the Company's PCA.

A. The outcome of the below items led to the Company's PCA because it can satisfy the Company's objectives of providing clean, reliable, and affordable energy while providing financial stability of the regulated utility:

1) $640 million cumulative savings for customers by accelerating retirement of coal and oil/gas peaking units replaced with the Covert, DIG, Kalamazoo, and Livingston plants (reference direct testimony of Company witness Coker);

2) Operating capability risks associated with continued operation of Campbell Units 1 and 2 and Karn Units 3 and 4 consistent with the design lives of those units (reference direct testimony of Company witness Kapala);

3) In the BAU reference case, gas units are the most economical resource to meet capacity needs prior to 2026 (reference direct testimony of Company witness Walz);

4) Electric supply reliability analysis conducted as a LOLE study by the Company shows events occurring nine times greater than NERC's one event in 10-year standard. While the Company economically benefits from shared market resources in MISO to help support the one event in 10-year standard, a reliance on others in and outside of Michigan to plan for and provide for Consumers Energy's needs carries significant risk to customers. Instead, the Company's PCA provides for the resources and energy to reliably meet customer needs every hour of every day (reference direct testimony of Company witnesses Walz and Clark);

5) The Company's Planet goals to achieve Net Zero Carbon Emissions by 2040 for all generating sources, and the opportunity to remove 63 million tons of carbon emissions from the atmosphere (reference direct testimony of Company witness Breining);

6) State and federal regulatory pressures to achieve carbon reductions of greater than 28% by the year 2025 (Michigan Directive 2020-10) and achieve 40-60% carbon reductions by 2070 under the 2° C scenario of the Paris Climate Agreement (reference direct testimony of Company witness Breining);

7) The positive financial impacts by accelerating the retirement of Campbell Units 1, 2, and 3 and Karn Units 3 and 4 based upon the recovery methods of the remaining book balances of these assets (reference direct testimony of Company witness Coker);

8) The results of the RFP conducted by an independent third party, CRA, to acquire an existing gas unit or units in or transferrable to Zone 7 in MISO in the next five years (reference direct testimony of Company witness Troyer); and

9) Stakeholder feedback received from the public, interested parties, and regulators (Exhibit RTB A-2 (RTB-2)).

Q. Does the PCA meet the planning objectives detailed earlier in your direct testimony?

A. Yes, it does. From a *People* perspective, the PCA's reliance upon demand-side management resources and renewable generation supports compliance with the Company's Clean Energy Goal, reduces waste, enhances reliability, keeps bills affordable, and aligns with stakeholders' desire for evolution of the Company's resource portfolio. The Company has demonstrated its commitment to communities and employees affected by past retirement decisions and is committed to do the same with the decision to retire Karn Units 3 and 4 in 2023 and Campbell Units 1, 2, and 3 in 2025. The PCA is shown to provide the necessary capacity and energy to reliably serve hourly and anticipated peak electric load plus PRMR in all seasons through the study horizon with the purchase of the Covert Plant and the DIG, Kalamazoo, and Livingston plants. The modular nature of the PCA created by the continued build of solar, batteries, and demand-side management programs further enhances reliability through reduced exposure to failures in energy transmission and generator outages. Finally, the Company anticipates no expected detrimental socioeconomic impacts, such as employment, for the local region of the Covert Plant and DIG, Kalamazoo, and Livingston plants proposed to be purchased as part of the PCA.

From a *Planet* perspective, the PCA is in full compliance with all environmental regulations and mitigates future financial risks of potential environmental regulation on fossil fuel generation. The PCA aggressively reduces waste, increases solar and battery generation, eliminates over 60 million tons of carbon from the environment, exceeds state targets and the Paris Climate Agreement targets, eliminates 3 billion cubic yards of ash waste, eliminates use of 220 billion gallons of fresh river and lake water, and reduces emissions of criteria pollutants (SO_2, NO_x, mercury, and particulate matter).

From a *Prosperity* perspective, the PCA will keep bills affordable and create modest to neutral savings for customers with the addition of low-cost resources and investments in existing resources versus investing in new-construction gas units with design lives of 50 or more years. So, too, do the proposals for recovery of remaining book balance, an improved avoided cost methodology and competitive procurement process, and the FCM for PPAs. The PCA allows the Company to adjust its plans in the future should lower-cost technologies become available or demand not materialize as forecasted in this IRP. Such adjustments will allow the Company to provide the right amount of capacity at the right time.

The PCA contains several proposals that will enable financial stability of the electric utility. If approved, these proposals will give the necessary confidence the Company and investors need to move forward with the PCA.

SECTION VI: DESCRIPTION OF SIGNIFICANT PROPOSALS AND SUMMARY OF REQUESTED RELIEF

Q. Please explain the Company's request with respect to the purchase costs for the Covert Plant and the DIG, Kalamazoo, and Livingston plants.

A. As discussed above, the Company selected a bid for the Covert Plant and a bid for the DIG, Kalamazoo, and Livingston plants as a result of an existing gas plant RFP issued January 2021. The Company's PCA proposed in this case includes the Covert, DIG, Kalamazoo, and Livingston plants and the assumption that the Company will accelerate the retirement of Karn Units 3 and 4 in 2023 and Campbell Units 1, 2, and 3 in 2025. The extensive evidence provided by the Company in this case establishes that the Company's proposed PCA, which includes the purchase of the aforementioned resources, represents the most reasonable and prudent means of meeting the Company's energy and capacity needs and therefore, the PCA should be approved. If the Company's PCA is approved by the Commission, the Company intends to go forward with the purchase of the aforementioned plants and requires the approval of the costs to purchase the Covert Plant and the DIG, Kalamazoo, and Livingston plants, pursuant to MCL 460.6t, in this case.

Under MCL 460.6t, the Commission is permitted to approve the costs for the purchase of existing electric generation facilities which are commenced within three years after the Commission's order approving an IRP. Specifically, MCL 460.6t(11) provides as follows:

> In approving an integrated resource plan under this section, the commission shall specify the costs approved for the construction of or significant investment in an electric generation facility, the purchase of an existing electric generation facility, the purchase of power under the terms of the power purchase agreement, or other investments or resources used to meet energy and capacity needs that are included in the approved integrated resource plan. The costs for specifically identified investments, including the costs for facilities under subsection (12), included in an approved integrated resource plan that are commenced within 3 years after the commission's order approving the initial plan, amended plan, or plan review are considered reasonable and prudent for cost recovery purposes.

The Covert, DIG, Kalamazoo, and Livingston plants represent existing electric generation facilities for which the Commission is permitted to approve the purchase price under the law and the Company will incur the costs to purchase those plants within the three years after the Commission's expected order approving this IRP on June 27, 2022 (i.e., by May 31, 2023 for the Covert Plant and by May 31, 2025 for the DIG, Kalamazoo, and Livingston plants). Therefore, the Company is requesting Commission approval of the acquisition and purchase costs of $815 million for the Covert Plant and $530 million for the DIG, Kalamazoo, and Livingston plants, in the manner described in the Company's direct testimony and exhibits, as reasonable and prudent for cost recovery purposes pursuant to MCL 460.6t.

With the approval of the above purchase costs by the Commission, the Company will include in retail rates all reasonable and prudent costs specifically approved pursuant to MCL 460.6t(11) that have been incurred to implement the approved IRP, in accordance with MCL 460.6t(17). This will be accomplished in future electric rate case proceedings. As explained by Company witness Battaglia, the total purchase costs for the DIG, Kalamazoo, and Livingston plants may ultimately be less than $530 million, but no less than $520 million, based on whether or not CMS Enterprises reacquires capacity that was sold to third parties. Therefore, if the Company does not ultimately incur the full $530 million in identified purchase costs for the DIG, Kalamazoo, and Livingston plants, the Company will only include the amounts in retail rates that it actually incurs.

Q. Please explain the Company's request with respect to the Commission's Code of Conduct in connection with the acquisition of the DIG, Kalamazoo, and Livingston plants.

A. The Company requests approval of the selection and proposed purchase of the DIG, Kalamazoo, and Livingston plants, as a result of a competitive solicitation, which are owned by subsidiaries the Company's affiliate CMS Enterprises, as compliant with the Code of Conduct. The competitive solicitation also complied with FERC standards for determining that an acquisition involving an affiliate will not adversely affect competition and is consistent with the public interest as it satisfied the four principles – Transparency, Definition, Evaluation, and Oversight – of FERC's solicitation guidelines. The purchase price for the Company's acquisition of the DIG, Kalamazoo, and Livingston plants from CMS Enterprises reflects a fair market price for the assets, and is lower than the Company's embedded cost of capacity. The transaction was part of the Company's 2021 competitive solicitation that was independently administered. The use of an independent administer allowed for an independent, fair, and transparent solicitation. It is under this process that CMS Enterprises was selected as an economical and fair market bid. Since the contract price is lower than the Company's fully embedded capacity costs, the Company's selection and proposed purchase of the plants complies with the Code of Conduct.

Alternatively, the Company requests a waiver of the requirement to comply with the Code of Conduct for the acquisition of the DIG, Kalamazoo, and Livingston plants. Such a waiver would be appropriate because the purchase agreement for the acquisition of the DIG, Kalamazoo, and Livingston plants was made pursuant to a market-based competitive solicitation conducted by an independent third party. The contract between the Company and its affiliate resulted from an arms-length transaction. There was no preferential treatment afforded to the affiliate. Customers benefit from the participation of the Company's affiliate in the competitive solicitation, and the potential harm which the Code of Conduct was intended to prevent is not present.

Q. Please explain the Company's request with respect to the recovery of the remaining net book balances and decommissioning costs of Karn Units 3 and 4 and Campbell Units 1, 2, and 3.

A. As detailed in the direct testimony of Company witnesses Watkins and Coker, the remaining net book balances of Karn Units 3 and 4 and Campbell Units 1, 2, and 3 are significant and valued at over $1.5 billion. A foundational component of the Company's PCA is the approval of the Company's proposed recovery method of the remaining net book balances of these plants which ensures that the Company will not be financially harmed by the accelerated retirements.

The Company is requesting approval to recover the remaining net book balances and decommissioning costs of Karn Units 3 and 4 and Campbell Units 1, 2, and 3 through regulatory asset treatment, with full return. As explained in the direct testimony of Company witness Coker, the Company is specifically proposing to continue to depreciate Karn Units 3 and 4 and Campbell Units 1, 2, and 3 at the current Commission-approved depreciation rates until base rates are reset in the next electric general rate case. In the next rate case filed after the conclusion of this IRP proceeding, the actual remaining net book balances would be removed from plant-in-service and accumulated depreciation accounts and placed into a regulatory asset. The Company proposes to set an annual amortization rate that allows for the recovery of the remaining net book balances and the decommissioning costs by 2031 for costs associated with Karn Units 3 and 4 and Campbell Units 1 and 2 and by 2040 for costs associated with Campbell Unit 3 (i.e., consistent with the design lives of each unit).

As explained in the direct testimony of Company witness Maddipati, the Company is proposing to recover the remaining net book balances consistent with the design lives of the units, as opposed to the proposed retirement dates, because it is consistent with the recovery currently in customer rates and balances the rate impacts of current customers with the impacts to future customers. The Company's proposed regulatory asset treatment is also a necessary element of the Company's PCA due to Generally Accepted Accounting Principles. Company witness Coker explains that, under Generally Accepted Accounting Principles, the net book balances of the plants must be removed from plant-in-service when it becomes probable that a plant will be abandoned before the end of its useful life. If the Commission approves the PCA in this case it would become probable, under accounting standards, that the plants will be retired and abandoned. If the Commission authorizes regulatory asset treatment with full return, a regulatory asset in the amount of the remaining net book balances would be recorded and no impairment loss would be recorded. However, if the Commission does not authorize a method of recovering the remaining net book balances of the plants including full recovery of financing costs, at the same time the PCA is approved, the Company would be required to write off a portion of the net book balances of Karn Units 3 and 4 and Campbell Units 1, 2, and 3 and record an impairment for accounting purposes.

The direct testimony of Company witness Maddipati further explains that, given, among other things, the impact of the Company's other recent securitizations for the Classic 7 and Karn Units 1 and 2, the Company does not agree with typical securitization of the remaining net book balances of Karn Units 3 and 4 and Campbell Units 1, 2, and 3 because securitizations are credit ratings negative for a Company and therefore would result in financial harm to Consumers Energy.

In summary, the Company would not be able to proceed with the PCA unless the Company is able to recover the unrecovered net book balances in a manner that preserves both the Company's credit and financial profile. The Company's proposal to recover the remaining net book balances of the to-be-retired units over their remaining design lives is a balanced proposal that would preserve the Company's credit and financial profile and is a requirement for the Company to proceed with the PCA.

Q. Please summarize all relief that the Company is requesting in this filing?

A. The Company is requesting that the Commission approve the Company's PCA as the most reasonable and prudent means of meeting the Company's energy and capacity needs over the 5, 10, and 15-year time horizons (2021-2035). The Company's PCA, which is inclusive of all other proposals presented by the Company in this proceeding, includes the following components and requests:

1) The accelerated retirement of the Company's Karn Units 3 and 4 by May 31, 2023, and the Company's Campbell Units 1, 2, and 3 by May 31, 2025, and the replacement of those resources with the purchase of existing gas resources, in addition to the expansion of the levels of solar and demand-side resources. The purchase of existing gas units will include the purchase of the Covert Plant by May 31, 2023, and the purchase of the DIG, Livingston, and Kalamazoo plants by May 31, 2025. The accelerated retirement and purchase of the aforementioned resources are conditioned on: (i) the approval of the Company's proposed regulatory asset treatment to recover the remaining net book balances of the above identified Campbell and Karn units through their current design lives, and (ii) approval of the acquisition and purchase costs of the Covert, DIG, Livingston, and Kalamazoo plants ($1.345 billion), in the manner described in the Company's direct testimony and exhibits, are reasonable and prudent for cost recovery purposes pursuant to MCL 460.6t;

2) Certain accounting approvals which include: (i) regulatory asset treatment, with full return, to recover the remaining net book balances of Karn Units 3 and 4 and Campbell Units 1, 2, and 3 through their current design lives;

(ii) approval to defer employee retention costs; and (iii) approval to make retirement transition costs a regulatory asset;

3) Approval of the selection and proposed purchase of the DIG, Kalamazoo, and Livingston plants by Consumers Energy 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. The competitive solicitation also complied with FERC's standards for determining that an acquisition involving an affiliate will not adversely affect competition and is consistent with the public interest as it satisfied the four principles – Transparency, Definition, Evaluation, and Oversight – of FERC's solicitation guidelines. 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, Kalamazoo, and Livingston plants from CMS Enterprises;

4) Improvements to the Company's currently approved IRP competitive procurement process used to acquire the new supply-side resources in the Company's PCA which include greater flexibility in the amount of capacity ultimately acquired in each solicitation and greater certainty regarding the Commission approval process for the new resources selected;

5) The continued use of the competitive procurement process for determining full PURPA avoided cost rates and the Company's capacity needs or sufficiency for the purposes of PURPA. The Company is also requesting certain modifications to its currently approved PURPA avoided cost construct. Furthermore, the Company is requesting a continuation of the Commission's determination that the Company does not have a PURPA capacity need so long as it is implementing the PCA, with the competitive procurement approach proposed by the Company;

6) Continued recovery of an FCM and application of that FCM to all new or newly modified PPAs. The Company is also proposing an adjustment to the methodology and level of FCM applied to PPAs, based on the FCM initially approved in Case No. U-20165; and

7) Approval of the acquisition and purchase costs of the Covert, DIG, Kalamazoo, and Livingston plants, in the manner described in the Company's direct testimony and exhibits, and the proposed EWR, DR, and CVR costs which will be commenced by the Company within three years following the Commission's expected approval of the Company's IRP as reasonable and prudent for cost recovery purposes pursuant to MCL 460.6t. The total costs that the Company seeks approval of include:

    a. $1.345 billion for the purchase costs related to the acquisition of the Covert, DIG, Kalamazoo, and Livingston plants;

b. DR costs for January 1, 2023 to June 30, 2025 ($23,751,000 capital, $3,100,000 O&M, $26,300,000 of incentive, to achieve a total of 641 MW (657 ZRCs) in 2025);

c. EWR costs for January 1, 2024 to June 30, 2025 ($226,721,558 O&M, $45,344,312 of incentive, 545,305 MWh savings, 879 MW savings); and

d. CVR costs for January 1, 2023 to June 30, 2025 ($9,736,315 capital, $1,203,14 O&M, 136,351 MWh savings, 56.81 MW savings).

The Company's IRP is truly integrated as all requests, as identified above, are fully interdependent. Approval of all identified requests are a necessity to fulfilling the PCA and providing customers a better plan for Michigan.

Q. Please summarize your direct testimony.

A. This IRP meets all applicable filing requirements. The PCA meets the Commission's and Company's planning objectives and is the most reasonable and prudent way to meet energy and capacity needs over the next 20 years.

This is an integrated plan in that the PCA is only possible with a supportive regulatory construct that includes recovery of remaining net book balances for Karn Units 3 and 4 and Campbell Units 1, 2, and 3. Such a regulatory construct will give the necessary confidence the Company needs to move forward with the PCA. The Company reserves the right to abandon or amend its PCA if the Commission rejects any of the Company's proposals presented in this IRP.

Q. Does this complete your direct testimony?

A. Yes, it does.

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 Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))))	Case No. U-21090

DIRECT TESTIMONY

OF

SARA T. WALZ

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

SECTION I: INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Sara T. Walz, 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 the Company?

A. I am a Principal Engineering Technical Analyst Lead in the Integrated Resource Planning Section of the Electric Grid Integration Department.

Q. Please describe your educational background.

A. I received a Bachelor of Arts degree in Mathematics in 2006 from Michigan State University and a Master of Science degree in Applied Mathematics in 2007 from North Carolina State University.

Q. Please describe your business and professional experience.

A. I joined the Company's Transactions and Resource Planning Department in January 2008. I was responsible for the Financial Transmission Rights monthly and annual allocation and auction. In September 2009, I began working in the Production Cost Modeling area of Transactions and Resource Planning, where I served as the primary modeler and subject matter expert witness for near-term fuel and purchased power expenses using the PROMOD production cost modeling software until May 2017. I was involved in the Strategist modeling performed for the Company's application of a certificate of necessity to build the Thetford generating plant in 2013, Michigan Public Service Commission ("MPSC" or the "Commission") Case No. U-17429. That case was ultimately withdrawn from the Commission's review in lieu of the purchase of the Jackson generating plant. In May 2017, I assumed the position of lead of the modeling team now referred to as "IRP Modeling and Analytics"; my responsibilities have included leading the team to complete modeling and support of the 2018 Integrated Resource Plan ("IRP") – the Company's first IRP filed under new state law.

Q. What are your present responsibilities and duties as a Principal Engineering Technical Analyst Lead?

A. Presently I am responsible for all long-term capacity expansion and production cost modeling used to inform the Company's long-term electric supply strategy decisions. My team and I utilize Energy Exemplar's Aurora software platform ("Aurora") to perform all aforementioned modeling.

Q. Have you provided testimony before the Commission ?

A. Yes, I provided testimony in the following MPSC cases on behalf of the Company:

- U-17095, the Company's 2013 Power Supply Cost Recovery ("PSCR") Plan;
- U-17095R, the Company's 2013 PSCR Reconciliation;
- U-17317, the Company's 2014 PSCR Plan;
- U-17317R, the Company's 2014 PSCR Reconciliation;
- U-17678, the Company's 2015 PSCR Plan;
- U-17678R, the Company's 2015 PSCR Reconciliation;
- U-17918, the Company's 2016 PSCR Plan;
- U-17918R, the Company's 2016 PSCR Reconciliation;
- U-18142, the Company's 2017 PSCR Plan case; and
- U-20165, the Company's 2018 IRP.

SECTION II: PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to support the Company's IRP and:

- Identify and describe the scenarios and sensitivities evaluated and presented in this IRP;
- Describe the planning and modeling process that was performed in support of this IRP;
- Discuss the design and results of the retirement analysis included in this IRP;
- Describe the resource options considered in the IRP analysis;
- Support the selection of the types of resources included in the Company's Proposed Course of Action ("PCA");
- Discuss the Company's Capacity Sufficiency Analysis ("CSA") to determine the potential for loss of load events;
- Describe how demand-side management programs were designed to be offered into the Aurora optimization simulations;
- Discuss modeling performed specific to existing natural gas assets for which the Company requests approval, as part of its PCA; and
- Present the results of the IRP and CSA modeling and provide interpretation of the economic and statistical results that informed development of the PCA.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits, all of which were prepared by me or under my supervision:

Exhibit A-4 (STW-1)	2021 IRP MPSC-Required Scenarios and Sensitivities;
Exhibit A-5 (STW-2)	2021 IRP Consumers Energy Scenarios and Sensitivities;
Exhibit A-6 (STW-3)	2021 IRP Existing Assets Zonal Resource Credits and Projected Generation;

Exhibit A-7 (STW-4)	2021 IRP Levelized Cost of Energy – Resource Screening;
Exhibit A-8 (STW-5)	2021 IRP MISO Market Topology;
Exhibit A-9 (STW-6)	2021 IRP Economic Benefits of CVR and EWR;
Exhibit A-10 (STW-7)	2021 IRP Demand Response Resource Blocks, by Scenario, for Aurora;
Exhibit A-11 (STW-8)	2021 IRP Portfolio Design;
Exhibit A-12 (STW-9)	2021 IRP Aurora NPV Results;
Exhibit A-13 (STW-10)	2021 IRP Aurora Resource Selections, by New Technology Resource;
Exhibit A-14 (STW-11)	2021 IRP Aurora Retirement Base Case Optimal Plans, PCA, and Alternate Plan;
Exhibit A-15 (STW-12)	2021 IRP Purchased Gas Units Operations;
Exhibit A-16 (STW-13)	2021 IRP Capacity Sufficiency Analysis Loss of Load Event Examples: High Renewable;
Exhibit A-17 (STW-14)	2021 IRP Capacity Sufficiency Analysis Loss of Load Event Examples: Controllable Generation;
Exhibit A-18 (STW-15)	2021 IRP Capacity Sufficiency Analysis Results: Heat Maps;
Exhibit A-19 (STW-16)	2021 IRP Retirement Analysis, PCA and Alternate Plan Cost Summary; and
Exhibit A-20 (STW-17)	2021 IRP Total Fuel Cost of Existing Owned Units, by Scenario.

Q. How is the remainder of your direct testimony organized?

A. The remainder of my direct testimony is organized in sections as follows:

SECTION III: SUMMARY

SECTION IV: SCENARIO AND SENSITIVITY DEVELOPMENT

SECTION V: PROCESS USED IN MODELING

SECTION VI: RESOURCE OPTIONS CONSIDERED IN THE IRP

SECTION VII: DEVELOPMENT OF DEMAND-SIDE OPTIONS FOR AURORA

SECTION VIII: OPTIMIZATION PORTFOLIOS

SECTION IX: PURCHASED GAS UNIT OPERATIONS

SECTION X: SUMMARY OF MODELING RESULTS

SECTION XI: CAPACITY SUFFICIENCY ANALYSIS

SECTION XII: CAPITAL, O&M, AND FUEL COST SUMMARY

SECTION III: SUMMARY

Q. Please summarize your direct testimony.

A. My direct testimony will provide the quantitative support for the PCA, discussed in the direct testimony of Company witness Richard T. Blumenstock, that was developed based on the lowest-cost resources selected from the hundreds of resource optimizations developed as part of this IRP.

I will show that the PCA was developed based on the resources chosen by computer optimization models that select the least-cost portfolio of resources available. The outputs of the model highlight the types of resources that provide the lowest cost to customers to meet resource planning requirements. As will be discussed later in my direct testimony, the scenario and sensitivity modeling ultimately led the Company to select a portfolio of resources for its PCA that includes the purchase of existing natural gas resources as well as large amounts of solar, with lesser amounts of Demand Response ("DR") and battery storage resources providing a balanced portfolio. Additional information regarding development of the PCA, based on model optimization results, can be found in the Summary of Modeling Results found at Section X of this direct testimony.

The development of this IRP includes thorough application of a variety of resource, operational, cost, and environmental inputs and data into computer-based models that developed short- and long-term resource plans. My direct testimony will demonstrate that the modeling process used to develop the IRP included in this filing was rigorous and comprehensive, consistent with good utility practice, followed the requirements detailed in Section 6t of Public Act 341 of 2016 ("Act 341"), and ultimately was used to identify the key elements of the best IRP for Michigan for both short-term and long-term planning periods.

Finally, my direct testimony will provide economic support of the Company's plans to exit coal within the next five years, invest in existing baseload generation resources to ensure electric supply reliability, invest in the growth of demand-side resources, and continue on the Company's clean energy plan of increasing levels of renewable energy resources over the next twenty years. My sponsored exhibits will also provide the economic support for the decision to retire the natural gas and oil-fired D.E. Karn ("Karn") Units 3 and 4 generating units, and the coal-fired J.H. Campbell ("Campbell") Units 1, 2 and 3 generating units. The investments identified in this IRP are part of the Company's PCA to provide near-term and long-term capacity to fulfill the needs of our customers.

<u>SECTION IV: SCENARIO AND SENSITIVITY DEVELOPMENT</u>

Q. What scenarios were included in the development of the modeling used in the IRP?

A. The scenarios and sensitivities modeled in the Company's IRP include the following:

- Scenarios defined within the Michigan Integrated Resource Planning Parameters ("MIRPP"), which were adopted by the Commission in Case No. U-18418 pursuant to Act 341, Section 6t. These major input assumptions are summarized in Exhibit A-4 (STW-1);

- The "Carbon Reduction Scenario," an additional scenario developed by the MPSC was order on February 18, 2021 in Case No. U-20633, which contemplates increases in electrification of various industries, including increases in electric vehicle ("EV") adoption and corresponding increases in customer demand – in combination with carbon reduction targets issued in Michigan Governor Gretchen Whitmer's executive directive ED 2020-10. This scenario is also included in Exhibit A-4 (STW-1); and

- Scenarios developed by the Company, which are largely created with the primary purpose of performing retirement analysis as required in the Settlement Agreement in Case No. U-20165 (the Company's 2018 IRP). These major input assumptions are summarized in Exhibit A-5 (STW-2).

Q. What sensitivities were included in the development of the modeling used in the IRP?

A. Thirteen sensitivities were required for the MIRPP scenarios, including the evaluation of impacts resulting from changes to the following assumptions: demand growth, increased energy efficiency (also identified as Energy Waste Reduction ("EWR")), the price of natural gas, return of customers to the utility currently taking service from alternative energy suppliers, higher carbon regulations, higher renewable portfolio standards, and, finally, a portfolio optimization that allows only combustion turbines to meet future customer needs. The Consumers Energy scenarios include 39 retirement sensitivities, as well as a number of additional sensitivities evaluating the impacts from changes to several input assumptions including EWR, Conservation Voltage Reduction ("CVR"), behind-the-meter-generation levels ("BTMG"), the effective load carrying capability ("ELCC") of solar, costs of projected transmission network upgrades, and the assumed discount rate.

Q. Please further describe the scenarios included in this IRP.

A. Under scenarios currently defined under MIRPP, three base case scenarios were evaluated: (i) a Business as Usual ("BAU") scenario, which is consistent with many of the Company's major assumptions such as customer demand, EWR, DR, cost of capital for new resource technologies, environmental regulations, and more; (ii) an Emerging Technologies ("ET") scenario, which assumes advancements in technologies and economies of scale that result in greater potential for DR, EWR, and other emerging technologies; and (iii) an Environmental Policy ("EP") scenario, which targets carbon reductions of 30% from 2005 to 2030. (See Exhibit A-4 (STW-1). In this scenario, it is assumed that renewable portfolio standards and goals are raised and that DR and EWR programs grow.

The fourth scenario, or the Carbon Reduction Scenario, is evaluated under EP input assumptions but assumes load growth at 1.5% year-over-year throughout the study period, to represent increased electrification in the energy sector as well as a 28% and 32% reduction in carbon emissions by 2025, compared to 2005 levels. (See Exhibit A-4 (STW-1). This scenario requires inclusion of the Company's PCA as the selected expansion plan; however, due to the increasing load growth – and corresponding increases in the Planning Reserve Margin Requirement ("PRMR") – additional resources must be selected in this scenario.

For the first three Consumers Energy scenarios, the majority of input assumptions match those of the BAU, ET, and EP scenarios, described above, with the exception of two input variables modified: 1) the assumed cost of natural gas; and 2) the levels of EWR included in the underlying load forecast. (See Exhibit A-5 (STW-2). The fourth Consumers Energy scenario reflects a collection of the Company's own assumptions under what is referred to as an Advanced Technologies ("AT") scenario. (See Exhibit A-5 (STW-2). This scenario represents a future in which advancements in electrified transportation drive acceleration of clean energy and creates a higher penetration of distributed energy resources. In the AT scenario, customer engagement in energy sources and consumption is assumed to increase, driving higher levels of EWR and behind-the-meter generation, either at the residential, commercial, or industrial customer levels. This collection of assumed changes in electric consumption result in a flat to declining load forecast. Other differences in this scenario include changes to capital cost forecasts of new resource technologies, natural gas price forecast, and changes to the makeup of the remainder of the regional energy market resources.

We have abbreviated the names of the eight base scenarios as follows:

1. BAU AEO – BAU, using natural gas prices from the U.S. Energy Information Administration's ("EIA") 2020 Annual Energy Outlook ("AEO") reference case, as required in the MIRPP;
2. EP AEO – EP, using natural gas prices from the EIA's 2020 AEO reference case, as required in the MIRPP;
3. ET AEO – ET, using natural gas prices from the EIA's 2020 AEO reference case, as required in the MIRPP;
4. CO_2 Reduction – this has underlying assumptions like the EP AEO, but with 1.5% load growth, CO_2 reduction targets by 2025 and the PCA as the basis of the new resource expansion plan;
5. BAU CE – BAU[1], using Consumers Energy's natural gas price projections;
6. EP CE – EP, using Consumers Energy's natural gas price projections;
7. ET CE – ET, using Consumers Energy's natural gas price projections; and
8. AT, using the EIA's 2020 AEO high gas and oil supply case.

Q. Why were the three Consumers Energy natural gas scenarios, using Consumers Energy's natural gas price projections, developed?

A. The MIRPP requires that "[n]atural gas prices utilized are consistent with business as usual projections as projected in the [EIA's] most recent [AEO] reference case." The Company has developed the Commission-required scenarios, using natural gas prices from the EIA's 2020 AEO. Those prices deviate materially from the Company's assumptions regarding

[1] References to "CE" in modeling scenarios are related to Consumers Energy's projections. BAU CE, EP CE, and ET CE scenarios are collectively referred to as "Consumers Energy scenarios" or "Consumers Energy gas scenarios."

gas price outlooks. See the direct testimony and exhibits of Company witness Brian D. Gallaway for additional details regarding the Company's projected natural gas prices versus the EIA 2020 AEO outlook.

As explained in the direct testimony of Company witness Blumenstock, one of the core objectives of the IRP is to determine appropriate retirement dates for the Company's existing fossil-fueled generating units. The Company believes it was most prudent to complete those evaluations using its own assumptions regarding future natural gas prices; therefore, the three scenarios, BAU CE gas, ET CE gas, and EP CE gas were created for the primary purpose of carrying out the retirement analysis. It should be noted that the retirement decisions are considered across a range of natural gas prices: 25% below the Consumers Energy gas price forecast, 25% above the Consumers Energy gas price forecast, and 50% above the Consumers Energy gas price forecast. Under this methodology of gas price risk evaluation, the Company ensures any decision regarding accelerated retirement of existing fossil-fuel generating units is considered under a wide range of future gas price outcomes – *including* the AEO gas price forecasts required in the AEO scenarios. See Figure 1 of this direct testimony.

Q. Why was the AT scenario developed?

A. The AT scenario was developed to consider a future in which increased customer engagement in energy sources and consumption drive increases in both customer-supplied generation (such as BTMG), and customer adoption of demand-side management ("DSM") programs (such as EWR). Specifically, an EIA forecast[2] of BTMG growth was included as a fixed resource to supply energy and capacity, and a transformational EWR outlook

[2] The BTMG forecast was based on EIA's 2020 Annual Energy Outlook (Low Cost Renewables case) of PV Generation Forecast (Residential – Table 21 and Commercial – Table 22) for the East North Central region.

was assumed, with levels remaining at 2% cumulative of prior year sales year-over-year. Higher levels of EWR and BTMG have the net impact of reducing the amount of energy and capacity the Company would expect to serve – a lower PRMR, and a net load shape that could flatten throughout the day.

On the other hand, the AT scenario contemplated increases in electrification, including EV adoption. An assumption of a 31% increase in EV adoption was considered, over the duration of the study period, which would result in increases in customer demand, likely during off-peak periods.

Q. How does the AT scenario differ from the three Consumers Energy scenarios (BAU CE, ET CE, and EP CE)?

The AT scenario differed from other Consumers Energy scenarios in the following ways: (i) natural gas prices were based in the EIA's 2020 AEO High Gas/Oil Supply case, which assumes natural gas prices are depressed, compared to the EIA Reference case; (ii) expansion of distributed energy resources is considered, with capital cost reductions assumed – capital costs for storage was assumed to decline to 50% below BAU by the end of the study period and distribution-connected solar is modeled at a 50% reduction compared to BAU; (iii) capital costs of transmission-connected solar was assumed at 35% below BAU; and (iv) lastly, a modeling methodology was considered in AT, in which, for non-Consumers Energy thermal generating units[3], the Aurora long-term capacity expansion simulations were allowed to economically retire units in advance of their current planned retirement dates. The methodology is referred to as "CanDrop" in Aurora.

[3] Non-Consumers Energy thermal generating units include thermal generating units outside of the Consumers Energy footprint but within the MISO model topology presented in Exhibit A-8 (STW-5).

Additional support of the underlying DSM input assumptions included in the AT scenario can be found in the direct testimony of Company witness Steven Q. McLean.

Q. Are the natural gas prices used in the eight scenarios based on reasonably current commodity price outlooks?

A. The gas prices used in the AEO gas scenarios and the AT scenario were from the EIA's 2020 AEO, published in February 2020. An updated 2021 AEO was published in February 2021; however, the Company was not able to utilize the February updates in this filing. Development of inputs used in modeling was initiated in January 2020 and required significant time to complete all required scenarios and sensitivities. Furthermore, decisions regarding the fossil-fueled generating unit retirements were based on modeling mostly completed prior to the 2021 AEO release. The 2021 AEO reflects slightly lower projected natural gas prices than the 2020 AEO starting in year 2025 and continuing through the planning period. Specifically, on average, starting in 2025, annual prices decreased by approximately 4%.

Gas prices used in the Consumers Energy gas scenarios are also based on projections from February 2020. More recent prices from February 2021 vary minimally from February 2020 projections (chosen to be consistent with timing of the 2021 AEO data release) for most years. In the first three years of the study period, 2021 through 2023, recent gas prices are higher than the February 2020 outlook (an average of 13% higher). In years 2024 and 2025, more recent projections are 3% higher than last years. Beginning in 2027, and continuing through most of the study period, the February 2021 outlook projects lower prices (an average difference of 5%) compared to the prices used in modeling.

Q. What are the likely impacts from the differences in gas prices identified?

A. Recent updates to the AEO gas price forecast and the Consumers Energy gas price forecast reflect decreases in forecasted natural gas prices compared to those used in IRP modeling. However, the Consumers Energy gas price difference of approximately 5% for most of the study period and the AEO gas price difference of approximately 4% are minimal and not expected to change the results of this IRP in any significant way. Specifically, such small differences are unlikely to change the resource plans in the Aurora optimizations, or Net Present Values ("NPV") differences between sensitivities that are presented.

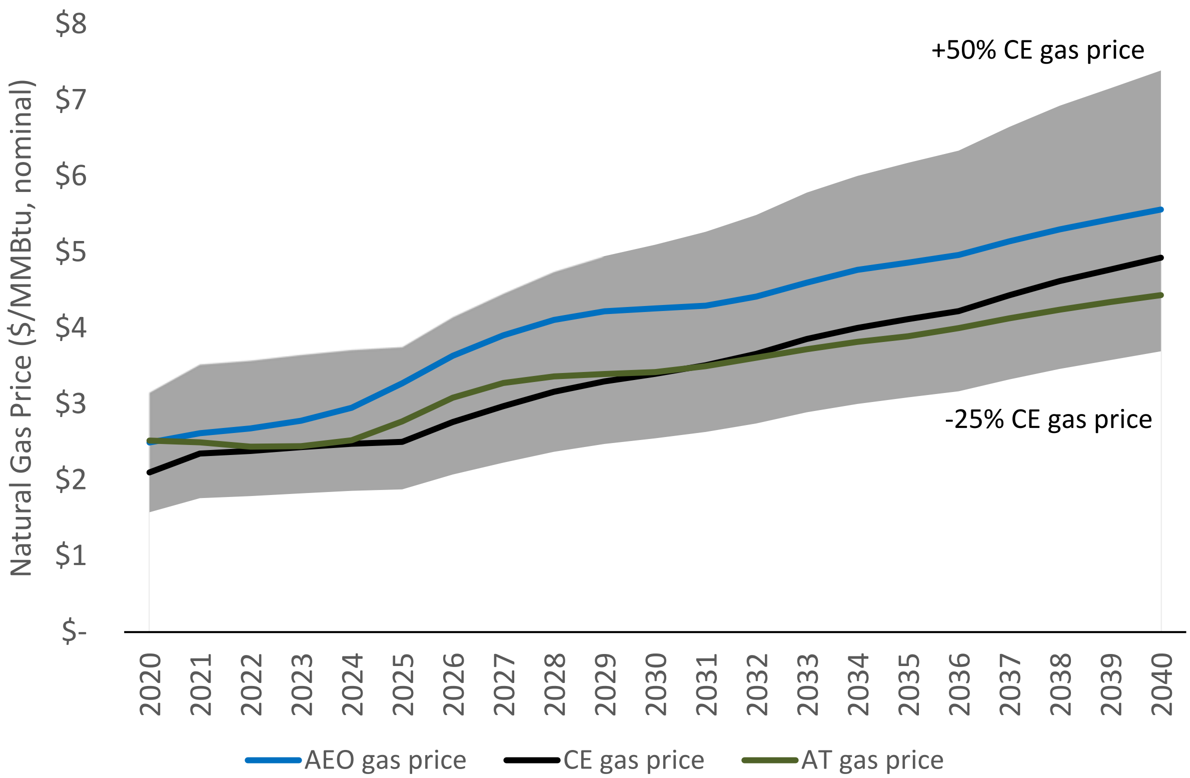
Q. How do the three natural gas price forecasts compare to one another?

A. The Consumers Energy gas price forecast is materially below the AEO gas price forecast. The AT gas price is materially below the AEO forecast; but varies over time in the relation to the Consumers Energy gas price forecast. Through the 2020s, the Consumers Energy gas price forecast is the lowest – lower than the AT gas price forecast. However, for years 2030 through 2040, the AT gas price forecast (which assumed depressed natural gas prices due to high supply of the commodity) drop below the Consumers Energy forecast.

Q. How does Consumers Energy address the differences in these natural gas price forecasts?

A. For purposes of retirement analysis included in this IRP, the Company performs a natural gas price sensitivity analysis that considers a sufficiently broad range of prices so as to include all price forecasts mentioned in this section. Additional discussion is included in the testimony of Company witness Anna K. Munie. Figure 1, below, includes the three gas price forecasts utilized in this IRP as line series, as well as a shaded region, which indicates the range of prices included in the Consumers Energy retirement analyses natural gas price sensitivities.

Figure 1: Natural Gas Prices Included in 2021 IRP Analyses



SECTION V: PROCESS USED IN MODELING

Q. Please provide a general description of the process used in modeling for the Company's IRP.

A. The process used for IRP modeling is based on the requirements contained in MCL 460.6t and in the MIRPP. Consumers Energy utilized its existing robust resource planning process, comprised of multiple inputs, calculations, and models, to meet these requirements. The planning process begins by developing base forecasts of key planning parameters. These key planning parameters include consideration of: (i) electric demand forecasts; (ii) existing supply-side resources; (iii) existing demand-side resources such as

EWR, CVR, and DR; (iv) renewable portfolio requirements; (v) applicable commodity pricing for carbon, natural gas, coal, and oil; (vi) environmental compliance requirements; and (vii) system constraints such as reserve margin, energy import capability, and capacity import capability.

The IRP modeling process includes multiple interrelated steps to develop and evaluate potential resource portfolios. These steps are iterative in nature because information is passed back and forth among the steps, and implications of some of the analytical steps could result in returning to previous steps for further analysis. A summary of each of the major steps is provided below:

1. Determine capacity position and first year of need;
2. Identify viable resource options;
3. Develop production cost models including appropriate inputs and assumptions;
4. Construct portfolios for evaluation;
5. Perform portfolio capacity expansion and production cost simulation analysis;
6. Evaluate portfolios using quantitative and qualitative measures;
7. Evaluate portfolios through scenario and sensitivity analysis;
8. Complete a risk analysis; and
9. Determine the most reasonable and prudent plan that meets the MPSC and Company planning objectives, and considers stakeholder feedback.

<u>Capacity Position</u>

Q. Step 1 of the process used in modeling is identified as determining capacity needs and the first year of need. Please explain how that determination is made.

A. Determination of capacity need is established by comparing projected peak demand levels and required reserve margins against existing and planned capacity resources.

Q. What are the Company's existing and planned capacity resources?

A. Section VI of this testimony identifies existing (or planned) resources included in the Company's base case, with details provided in Exhibit A-6 (STW-3).

Q. How does the Commission final Order in the Company's 2018 IRP (Case No. U-20165) impact existing and planned capacity resources?

A. The approved Settlement Agreement from MPSC Case No. U-20165 (the Company's 2018 IRP) provided approval for the recovery of costs for only the first three years of the study period. Specifically, the approval included the Company's plans to expand DR to 607 MW through year 2022; expansion of EWR at 2% of prior year sales through year 2023; and the acquisition of 1,100 MW of solar capacity through year 2024.

Q. In this IRP, how is the Company treating all remaining capacity resources included in the long-term plan presented in the 2018 IRP?

A. All remaining resources included in the long-term plan presented in the 2018 IRP will be removed from the portfolio as part of this IRP and re-evaluated for economic consideration. The remaining portfolio of resources, along with the corresponding date assumed as each resource's current end of life is compared to the Company's base case forecasted PRMR[4], which identifies years in which a shortfall of capacity occurs.

Q. What is the goal of an IRP as it relates to PRMR?

A. The goal of an IRP is to develop a plan to meet PRMR in each planning year of the study horizon.

[4] The planning reserve margin requirement (PRMR) is calculated based on the Company's annual forecast of bundled customer demand at the time of the MISO peak demand, plus approximately 8.9% reserves.

Q. When does the Company anticipate a capacity need under the assumptions identified above?

A. Figure 2, below, presents the result of the aforementioned comparison for the Consumers Energy scenario base case and indicates that under current assumed retirement schedules, the Company has no capacity need until 2029.

Figure 2: Consumers Energy Scenario Base Case Balance of Supply and Demand to Meet PRMR

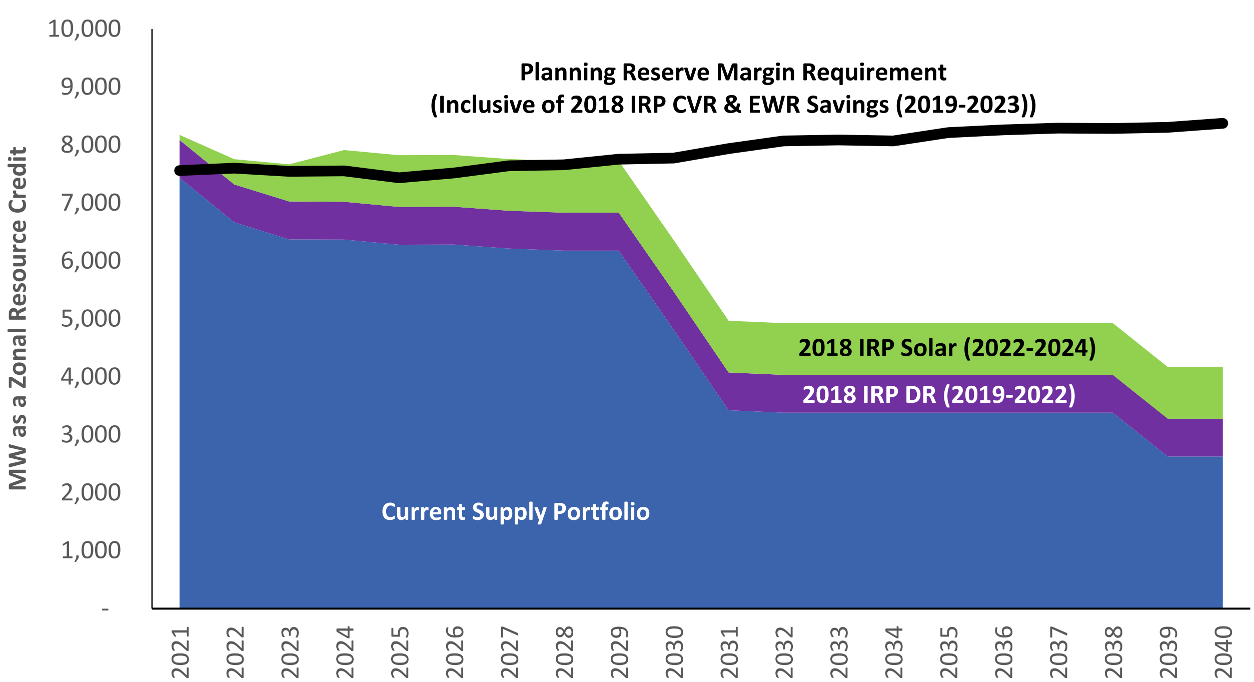
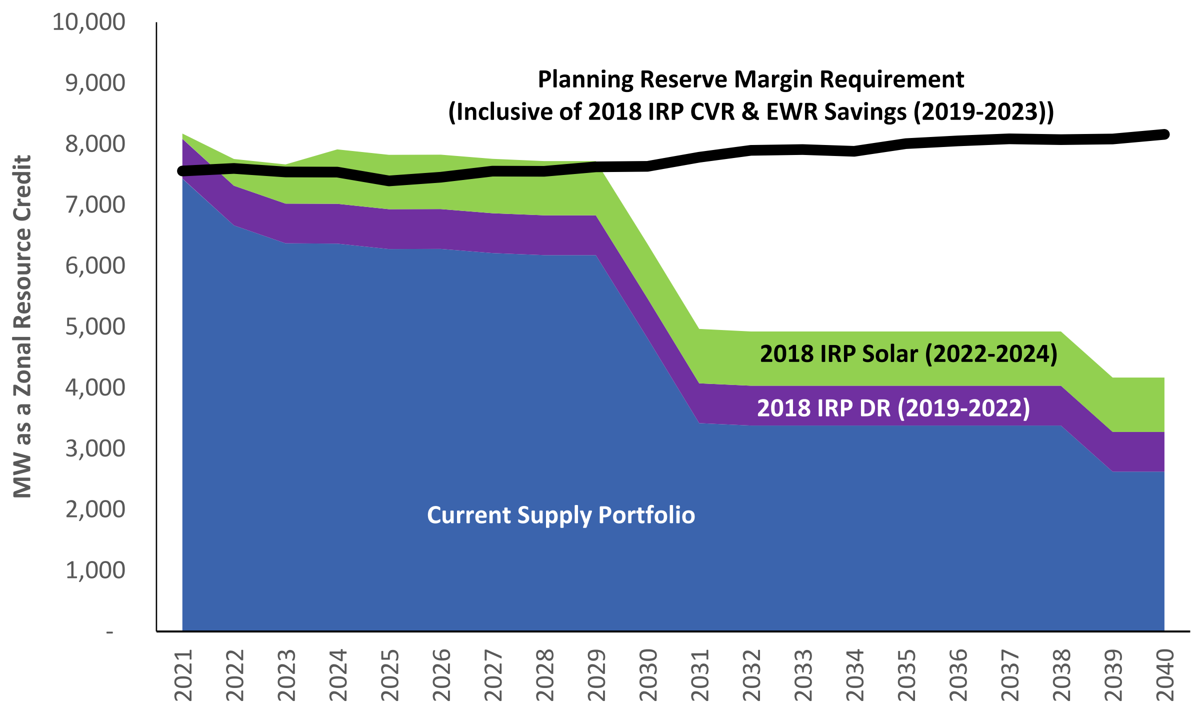


Figure 3 is the same comparison, but for the MPSC scenario base case:

Figure 3: MPSC Scenario Base Case Balance of Supply and Demand to Meet PRMR



Viable Resource Options

Q. Step 2 of the modeling process requires identification of viable resource options considered by the Company to meet future peak demand requirements. Please explain.

A. Identification of viable resource options requires a review of existing resources as well as potential resource options. Existing resources include the generating units owned by the Company, energy and capacity supplied through Power Purchase Agreements ("PPAs"), existing transmission capabilities, short-term or spot market purchases, and demand-side resources currently available to the Company. Potential resource options include additional new generating unit technologies, transmission expansion projects and upgrades, additional short-term or spot market purchases, and expanded EWR and demand-side resources. More information is provided in Section VI of this direct testimony.

Development of Production Cost Models

Q. How were the production cost models and inputs for various assumptions developed in Step 3 of the modeling process?

A. The input data required to develop the models is extensive due to the volume and complexity necessary to perform long-term capacity expansion ("LTCE") and production cost modeling. Many major input assumptions to the base models used were explicitly defined in the MIRPP.

Q. What were the sources of the major assumptions and forecasts modeled in this IRP?

A. The Company relied upon internal and external subject matter experts to develop many of the major assumptions and forecasts modeled in the IRP. Subject matter experts are included as witnesses in this proceeding. Below is a discussion of each of the major input assumptions and the source for those input assumptions:

- The first major assumption collected was a series of load forecasts. Six load forecast outlooks were developed for this IRP. Three base load forecasts were developed for the first eight scenarios.
  - Under the Consumers Energy gas scenarios and sensitivities, a base load forecast that assumed EWR levels at 2% through 2023 and 1% cumulative in years 2024-2040 was developed.
  - For the AEO natural gas base case scenarios and most sensitivities, a base load forecast that assumed EWR levels at 2% through 2023 and 1.5% cumulative in years 2024-2040 was developed. The exceptions to that generality are three load forecasts developed for the following sensitivities: 1.5% load growth, 2.5% EWR, and 50% Retail Open Access ("ROA") return.
  - The final load forecast developed was for evaluation in the AT scenario. This base load forecast assumed EWR remained at 2% throughout the study period, included increased consumption for electric vehicle charging, and also included reduction in forecasted demand to represent behind-the-meter generation. Behind-the-meter generation is supply sources at customer locations. Since these are such small sources of electric supply, and since they are behind the meter and not accounted

for on the utility distribution or transmission systems, the energy is modeled as a *reduction in load* instead of a supply resource.

For further information regarding load forecast development, please see the direct testimony of Company witness Eugène M. Breuring.

- An accounting of all existing supply and demand-side resources was undertaken. An overview of the Company's existing portfolio can be found in Exhibit A-6 (STW-3), as well as Section 7 of the IRP Report, Exhibit A-2 (RTB-2). For additional information on existing units and their projected retirement dates, please see the direct testimony of Company witness Norman J. Kapala.

- The next major assumption included existing renewable energy inputs, including output, capacity factor, and tax credits. This information was used as an input in all base case scenarios and sensitivities. For further information regarding renewable energy assumptions and inputs, please see the direct testimony of Company witness Teresa E. Hatcher. For further information regarding Production Tax Credit ("PTC") and Investment Tax Credit ("ITC") laws related to renewable energy technologies, please see the direct testimony of Company witness Carolee Kvoriak.

- The next major assumption included existing and capacity expansion options for EWR programs, including incremental decreases in retail sales and forecasted peak demand and impact. This information was used as an input in all base case scenarios and sensitivities. For further information regarding EWR programs and assumptions, please see the direct testimony of Company witness McLean, and Section VII of this direct testimony.

- The next major assumption was regarding demand-side management programs, including direct load control, dynamic peak pricing, CVR, and incremental DR. This information was used as an input in all base case scenarios, with varying levels of growth and expansion between BAU, ET, and EP. For more information regarding demand-side management programs, please see the direct testimony of Company witnesses Matthew S. Henry for CVR, and Emily A. McGraw for DR, as well as Section VII of this direct testimony.

- The next major assumption was regarding operating parameters and capital and operating costs for new supply-side resources (Combined Cycle ("CC"), Combustion Turbine ("CT"), wind, solar, and battery storage). The capital costs for certain resources were specified for each given scenario (for example, solar capital costs in the ET and EP scenarios are required to be 35% below BAU). For more information on the new supply-side technology resources, please see the direct testimony of Company witness Jeffrey E. Battaglia.

- The next major assumption was regarding network upgrade costs for all new generation resources. The information was used in all base case scenarios and sensitivities. For more information on network upgrade costs, please see the direct testimony of Company witness Benjamin T. Scott.

- The next major assumption was the amount of capacity import and export capabilities into and out of Zone 7. Please see the direct testimony of Company witness Scott for additional information.

- The next major assumption was the levels of effective load carrying capability ("ELCC") for *new* technology resources, which determines how much of a resource's installed capacity can be counted to meet the PRMR. This information is published by the Midcontinent Independent System Operator ("MISO") on an annual basis in its Wind & Solar Capacity Credit report[5] or calculated, using MISO-published class average equivalent forced outage rates.

- The next major assumption was in regard to forecasted fuel prices throughout the planning period. Fuel price forecasts include pricing for coal, natural gas, and oil. This information was used in the base case for all identified scenarios and sensitivities, with the exception of the 200% gas sensitivity, in which the projected cost of natural gas (based on EIA AEO natural gas price) was assumed to double by the end of the planning period. For more information regarding fuel prices and forecasts, please see the direct testimony of Company witness Gallaway.

- Existing PPAs with Non-Utility Generators were assumed to expire at existing contract expiration dates. However, as discussed in the direct testimony of Company witness Keith G. Troyer, some PPAs were assumed to continue to be renewed and are included as an aggregated generating resource in the base case scenarios and sensitivities. The contract with Entergy Nuclear Power Marketing, LLC for capacity and energy provided by the Palisades Power Plant ("Palisades") was assumed to expire in May 2022. The contract with Midland Cogeneration Venture Limited Partnership ("MCV") is assumed to expire in May 2030, as approved by the MPSC Commission in U-20896. For more information on these and other wholesale energy and/or capacity contracts, please see the direct testimony of Company witness Troyer.

- The final major assumption made was regarding economic parameters such as an assumed discount rate and Fixed Charge Rate ("FCR"). All base scenarios, and all MPSC-required sensitivities, were modeled using an assumed rate of return as approved in Case No. U-20134. A modeling sensitivity was run utilizing a 2.5% discount rate to consider impacts to NPV results at what can be considered a "social discount rate," closer to the rate of economic inflation. This sensitivity is presented in this IRP in response to several internal and external discussions regarding the appropriate rate by which to discount future customer costs. This modeling sensitivity will inform directional impacts that lower discount rate might have on resulting modeling assumptions, inputs, resource

[5] https://cdn.misoenergy.org/2020%20Wind%20&%20Solar%20Capacity%20Credit%20Report408144.pdf

plans, and associated NPVs within the different scenarios. Please see Section X of this direct testimony regarding modeling results and conclusions for further discussion.

Q. How were fossil-fueled generating unit retirements addressed in the base case scenarios?

A. With regard to the fossil-fueled generating unit retirement analysis previously referenced, the Company embedded the outcome of that analysis as an input to its base cases for the AEO gas price outlook scenarios. Specifically, the Company's base capacity outlook assumes retirement of Karn Units 3 and 4 in 2023, and assumes retirement of Campbell Units 1, 2, and 3 in 2025. Accordingly, for clarity, any discussion related to base case will hereafter assume that "base case" refers to Consumers Energy gas cases in which Karn Units 3 and 4, and Campbell Units 1, and 2, are assumed to operate through 2031 and Campbell Unit 3 is assumed to operate until 2039, while "retirement base case" will refer to cases in which Karn Units 3 and 4 are assumed to retire in 2023 and Campbell Units 1, 2, and 3 in 2025. The details of the retirement analysis are described in detail in the direct testimony of Company witness Blumenstock.

Q. Were the decisions regarding the use of inputs, developed by subject matter experts in this case, in the modeling made by you or under your supervision?

A. The development of production cost models for use in an IRP requires careful development of input assumptions from many subject matter experts. All inputs and modeling decisions were carefully reviewed by me or under my supervision.

<u>Construction of Optimization Portfolios</u>

Q. Describe how portfolios were constructed for evaluation, Step 4, of the modeling process.

A. Section VIII of this direct testimony details development of optimization portfolios. Generally speaking, a portfolio is a collection of resources (supply-side or demand-side) that can be used to fill a capacity need. Several different combinations of resources can be offered into the optimization and are selected by Aurora based on the lowest-cost outcome, from all possible options considered. The outcome of Aurora – the selected mix, amounts, and timing of resources – is then evaluated for relative cost, feasibility, resource diversity, environmental impacts, and more.

<u>Capacity Expansion and Production Cost Simulations/Evaluation of Portfolio Using Qualitative and Quantitative Measures</u>

Q. Step 5 requires performing capacity expansion and production cost simulation analysis and Step 6 requires evaluation of portfolios using quantitative and qualitative measures. How are these steps of the modeling process performed?

A. The Company conducted this analysis using Aurora, a computer software application.

Q. Please describe the Aurora software, and in what capacity that software was utilized.

A. The Company uses proprietary data and software programs in its integrated resource planning activities. The Company uses Aurora to develop its resource plan and alternatives. Aurora, a computer software application developed by Energy Exemplar ("EE"), supports electric utility decision analysis and corporate strategic planning. The Company also uses EE's database, which is used primarily for regional market modeling of energy resources and demand.

Q. Please identify the entity responsible for development of the models used in the IRP process.

A. The models were developed solely by the Company. Models of Consumers Energy's system were derived from input data provided by internal sources. Models of the regional market area outside of Consumers Energy's service area were derived from a mixture of sources including EE's database software, publicly filed documents, and internal planning assumptions.

Q. Please provide a general description of the Aurora modeling process.

A. The Aurora model simulates the commitment and dispatch of the Company's generation resources and the resources of all generators in the MISO footprint on the basis of a typical week representing each month over the planning period. The planning period for the IRP covers the 21-year period beginning January 1, 2020 and ending December 31, 2040.

In capacity expansion mode, the software selects incremental capacity additions from a selection of various resource options according to technology, amount, and timing to arrive at a least-cost resource plan that is a co-optimization of meeting hourly energy requirements as well as ensuring that required capacity reserve margins are maintained. Aurora will consider several alternative combinations of resources offered within user-defined modeling constraints and then rank the multiple combinations in economic order. To do so, the software calculates the costs associated with variable Operating and Maintenance ("O&M") expense, fuel expense, and emission expense for each hour of operation using the least expensive units to generate in each hour, abiding by operational constraints. For units added to maintain required capacity reserve margins, the model also calculates the economic carrying costs[6] and operating costs for each unit added, but does not include the carrying costs or fixed operating costs of units already included in rate base. The IRP modeling also excludes some fixed costs for existing resources that are common to all scenarios and sensitivities and have no impact on generating unit dispatch and resource plan optimization results.

With the nominal values developed for each month of the planning period, the NPV of the revenue requirement[7] is calculated and the alternative resource plans considered within the model are ranked in economic order from lowest to highest NPV. Post-optimization, any surplus capacity that remains after PRMR are met is assumed to be sold at the market price of capacity[8]. The surplus capacity revenue is not calculated within the model so as not to influence the model into building or adding new resources simply to sell off into the market. The result of this overall modeling process is the identification of the most cost-effective resource portfolio for each scenario and sensitivity.

Q. Is this how the eight scenarios identified earlier in this testimony were modeled?

A. Yes. As mentioned earlier, eight scenarios were evaluated in this IRP along with multiple sensitivities on key parameters in all scenarios. For each scenario and sensitivity, multiple Aurora-selected resource combinations for the Company were constructed and evaluated based on criteria such as cost, resource diversity, feasibility, and environmental impact.

[6] The Economic Carrying Charge ("ECC") is a method for quantifying capital cost streams in financial analysis and resource planning. The ECC is used in resource optimization models such as Aurora because it appropriately allocates the portion of capital costs to a project for a given time period, in the case that the project lifetime does not exactly align with the planning period of the model run. The ECC method also makes feasible a comparison of resources with different lifespans and commercial operation dates.
[7] NPV of the revenue requirements represents the current value (2020 dollars) of a stream of annual revenue requirements the Company must receive from its customers in order to cover all costs, operating expenses, taxes, depreciation, and return on investment.
[8] The market price of capacity in this IRP is assumed to be 75% of the Cost of New Entry ("CONE") of a CT unit. The value of CONE was published by MISO, as submitted to the Federal Energy Regulatory Commission in September 2019 for planning year 2020-2021.

Additionally, since the entire MISO market area is represented in the Aurora IRP model, for each scenario and many sensitivities, capacity expansion simulations were performed for the entire regional market area. Based on the optimized regional market area, the model then was able to optimize the Consumers Energy system. This methodology provides a balanced view of long-term reliability requirements in the study for the Consumers Energy system, the Lower Peninsula of Michigan, as well as the entire MISO market footprint. The result of this multi-step modeling process is a comprehensive plan that considers the interchange of power between the Consumers Energy system and the rest of the MISO market.

Q. Please describe the factors affecting model accuracy.

A. Several key factors influence the accuracy of the modeling results. It should be noted that, in this context, model "accuracy" refers to the degree to which the model can be expected to accurately reflect future conditions. The key factors influencing model accuracy include the validity of input assumptions, complexity of generating unit operations, and the complexity of the interconnection between systems. The Company took great care to develop accurate and valid input assumptions for the required scenarios and sensitivities; however, as with any forecast, a high degree of uncertainty over a 20-year planning period exists. As discussed at length in the direct testimony of Company witness Blumenstock, the Company's PCA mitigates, to great degree, the execution risks inherent in a typical large-scale utility resource plan. Specifically, the Company's PCA provides for a modular and adaptable resource plan that can evolve and shift with the inevitable changes to various input assumptions such as cost of new technologies, performance of new technologies, remaining life of existing assets, significant changes in customer demand, and environmental regulations.

Q. Please describe the sensitivity of forecasts to variability in assumptions.

A. Because the forecasted assumptions used in the modeling of the Consumers Energy system are variable and statistical in nature, it is critical to ensure that the assumptions used in the various scenarios and sensitivities cover the range of reasonably possible values. Inherent variability and risk associated with input assumptions were addressed in the initial phases of the IRP process through the stakeholder engagement process and thoughtful development of the scenarios and sensitivities to include specific parameters known to be key uncertainties. Additional details regarding this process are provided in the direct testimony of Company witness Blumenstock.

Q. Did the Company seek third party industry expert assistance for this IRP, and in what capacity was this assistance utilized?

A. Yes. The Company contracted a third-party review of its modeling through Siemens PTI Consulting. The Aurora models used in support of the IRP were provided to Siemens in order for them to review input assumptions, modeling methodologies and model selections. The detailed report of Siemens review is included in Company witness Blumenstock's Exhibit A-3 (RTB-3).

<u>Portfolio Analysis</u>

Q. Step 7 of the modeling process requires evaluation of portfolios through scenario and sensitivity analysis. Please explain that process.

A. Section X of this direct testimony, Summary of Modeling Results, provides evaluations, comparisons, and key conclusions and observations of the scenarios and sensitivities evaluated in this IRP.

Risk Analysis

Q. Please discuss Step 8, completion of a risk analysis.

A. The Company completed multiple levels of risk assessment within this IRP, including Stochastic risk analysis, portfolio risk assessment, scenario and sensitivity modeling and electric reliability analysis. Section XI of this direct testimony discusses the electric reliability risk analysis, while the testimony of Company witness Munie discusses the remaining risk assessments.

Determination of the Proposed Course of Action

Q. Please discuss Step 9, the determination of the most reasonable and prudent plan, the best IRP for Michigan.

A. Final development and selection of the PCA is discussed in Section X of this direct testimony, as well as in the testimony of Company witness Blumenstock.

As described above, the Company's nine-step approach to fulfilling the requirements of an IRP is a multi-step process that has been designed to evaluate a broad range of potential resource portfolios across identified scenarios and sensitivities to determine the amounts and types of resources that best meet the long term needs of Michigan from a variety of perspectives.

SECTION VI: RESOURCE OPTIONS CONSIDERED IN THE IRP

Q. What assumptions regarding existing and planned supply-side resources are included in the IRP?

A. The Company's diverse portfolio of existing generating resources includes a mix of owned resources and PPAs. Company witnesses Blumenstock, Kapala, Troyer, McLean, Hatcher, Henry, and McGraw describe the IRP assumptions related to these existing supply and demand-side resources, as well as currently planned additions, such as future projects included in the Company's Renewable Energy Plan and projected expansion of EWR and DR programs. The assumptions regarding these existing and planned supply and demand-side resources are common to all scenarios and sensitivities within the IRP. In addition to resources included in Exhibit A-6 (STW-3), the base case scenarios include the following major planned capacity resources:

- EWR savings at 2% through 2023 and dropping to 1.0% cumulative for years 2024-2040;
- Addition of the Heartland, Crescent and Gratiot wind farms;
- Addition of the River Fork PPA, 100 MW by 2021;
- Addition of 584 MW of PURPA QF solar capacity by 2023;
- Addition of 1,100 MW of 2018 IRP approved solar capacity by 2025;
- Increasing levels of DR, reaching 607 MW by 2022;
- The expiration of the Palisades PPA in May of 2022;
- The expiration of the MCV PPA in May of 2030;
- The retirement of Karn Units 1 and 2 in 2023;
- The retirement of Karn Units 3 and 4 in 2031;
- The retirement of Campbell Units 1 and 2 in May 2031;
- The retirement of Campbell Unit 3 in May 2039; and
- The operation of the Zeeland, Jackson, Ludington, hydro and other renewable facility resources through the duration of the study period.

Q. Please explain Exhibit A-6 (STW-3).

A. Exhibit A-6 (STW-3) provides information regarding the Company's 2021 IRP Existing Assets Zonal Resource Credits[9] and Projected Generation. The first four pages of Exhibit

[9]A zonal resource credit is equivalent to 1 MW of resource capacity, discounted for the resource's effective forced outage rate.

A-6 (STW-3) provide the zonal resource credits each generating unit in the Company's portfolio contributes, by year. Page 1 includes owned generating units; at the bottom of page 1, the listing of non-utility generators ("NUG") begins and continues onto pages 2 through 4. Some of the contract names may be repeated; for example, Adrian Energy Associates appears on line 55 of page 1 and again on line 117 of page 2. This is because the Company assumes that certain PURPA qualifying facility ("QF") contracts that have an expiration date specified may decide to sign a new contract under the same facility; therefore, as the contract expires, as indicated in the section titled "Non-Utility Generators (NUGS)," some contracts pick up where the current contract expires and is presented under the section called "New Contracts w/ Existing PURPA QFs".

Beginning on page 5, the projected generation in MWh is presented for each resource, as projected under the BAU base case. While most lines in Exhibit A-6 (STW-3) represent a single plant or resource, page 6, lines 75 and 76 represent an aggregate of the resources that are assumed to be available under the new contracts with existing QFs.

Q. What resources, other than the existing and planned resources previously described, were considered as potential supply options to serve demand in the future?

A. As part of its planning process, the Company considered a wide range of supply-side resources to serve future electric demand. Due to the volume of calculations made by the Aurora model as it solves for all potential solutions to satisfy the model's constraints, not all possible resources are made available for selection in every scenario. Some resource technologies, therefore, were "screened out" before the scenarios and sensitivities were modeled. The technologies were screened on criteria such as commercial availability, cost, scale, resource type (e.g., peaking, intermediate, and baseload), technical viability, and other considerations. New-construction technology resources that were screened out include the following:

- Thermal Storage - An initial technical screening indicated thermal storage was a higher cost application than other options associated with energy storage;
- Compressed Air - An initial technical screening indicated compressed air technology did not demonstrate enough technological advancement to be applied at a utility scale level;
- Flywheel - An initial technical screening indicated flywheel technologies were a higher cost application than other options associated with energy storage;
- Combined Heat and Power - Based upon Company subject matter expert feedback, the current and future economics and growth of Combined Heat and Power does not reflect a feasible alternative to consider as an alternate resource. The need for a steady steam supply tied to site-specific requirements makes this type of facility less viable then other resources;
- Fuel Cells - Initial technical screening indicated fuel cells were a higher cost application than other options associated with energy storage; and
- Geothermal - An initial technical screening indicated geothermal storage did not demonstrate enough technological advancement to be applied at a utility scale level.

Q. Please discuss how resources not screened out were then considered?

A. A preliminary economic analysis of the remaining new-construction technologies not screened out was performed using a Levelized Cost of Energy ("LCOE") comparison between similar technologies. Exhibit A-7 (STW-4) presents a comparison, based on the LCOE, of the various resources considered for final selection to be offered into the capacity expansion runs.

Q. What does an LCOE comparison do to assist in determining potential supply options to meet demand in the future?

A. An LCOE comparison allows a comparison of resources based on the amount of energy delivered by that resource, relative to the costs of construction, O&M, fuel, applicable network upgrade costs, as well as any offsetting revenues provided via tax credits or other means. The levelizing function allows the Company to take a varying stream of numbers and reduce them to one value, representing the entire period. Usually costs increase over time; levelization takes these increasing values, discounts them, and expresses the result as one number, usually in the current year dollars. However, it is very important to note that while LCOE can be a useful tool for comparison across multiple technologies, it has pitfalls as well. Specifically, for resources that are designed primarily to provide capacity, with potentially very little energy production, the LCOE of that resource can look poor, relative to other resources. Exhibit A-7 (STW-4) compares most resources according to the magnitude of their LCOE; however, a second page was necessary for DR, since those resources produce very little energy and have resulting high LCOE values.

Q. How did the Company respond to its supply option review?

A. As a result of the supply option review, the Company has focused its modeling on the following specific supply-side technologies: natural gas-fueled CTs, natural gas-fueled CC units, natural-gas fueled Reciprocating Internal Combustion Engine units, wind, solar, and battery storage. Resources such as coal, nuclear, and H-class CTs were not included in the portfolio optimizations. Coal and nuclear are not attractive resource options because of intensive capital costs and long time periods required for construction, and coal does not align with the Company's clean and lean objective. H-class CTs had high LCOE and did not provide the higher levels of Zonal Resource Credits ("ZRCs") as F-class CTs.

For details regarding the operating parameters and costs for natural-gas fueled, renewable energy, and storage technologies, please see the direct testimony and exhibits of Company witness Battaglia and Company witness Nathan J. Washburn.

Finally, for purposes of the development of the reference portfolio, described later in this direct testimony, the Company considers the hypothetical capacity replacement in which other MISO market participants may have capacity available for sale from existing and new generating facilities. For purposes of comparison, the Company evaluated a portfolio in which capacity can be purchased on a short-term or spot basis at a forecasted market capacity price.

Q. What assumptions regarding existing and currently planned demand-side resources are included in the IRP?

A. Existing and planned demand-side management programs generally fall into two categories:

1. Peak, or demand, load management programs that are designed to reduce demand during system peak hours, thereby avoiding or deferring new capital investment for generation and transmission; and
2. EWR that is designed to reduce long-term energy use through increased efficiency of energy consuming equipment, conservation programs that promote the use of more energy efficient building materials, and educational programs that promote the merits of lower overall use of energy and attempt to motivate a change in customer behavior.

Demand-side controls and EWR programs have and will continue to be effective resource options for the Company. Accordingly, the IRP includes forecasts of expanded EWR and demand reduction programs, as discussed in the direct testimonies of Company witnesses McLean and McGraw.

Q. Were additional energy efficiency and demand-side resources, other than what was previously described, modeled in the IRP as potential resource alternatives to meet future demand?

A. Yes. Additional demand-side management measures were evaluated in the IRP modeling through several scenarios and sensitivities, as presented in Section IV of this direct testimony, and were also offered for economic selection in the Aurora optimization simulations. The program and cost assumptions related to these demand-side management options are summarized in the direct testimony of Company witnesses McLean, Henry, and McGraw, as well as Section VII of this direct testimony.

Q. What assumptions regarding existing transmission resources are included in the IRP?

A. Two fundamental assumptions in the Company's resource need assessment and planning process are the transmission topology and the representation of the constraints and limitations on the existing transmission system. The transmission topology can best be represented by a series of zones representing "transmission areas" or "zones," which are interconnected by transmission "paths." Within each of the zones are the hourly customer loads and electric generating resources. The paths reflect the aggregate import and export limitations of all transmission lines between the zones. Exhibit A-8 (STW-5) provides the Company's representation of the basic transmission topology for the MISO market footprint within the Aurora IRP model. Further discussion of the import and export capabilities is also provided in the direct testimony of Company witness Scott.

Q. Were transmission options, other than what was previously described, considered as a supply resource in the IRP?

A. Yes. The IRP considers the potential role of transmission expansion in helping to meet future demand requirements. Company witness Scott discusses the various transmission expansion options that were evaluated although not explicitly modeled in the IRP.

Q. Were there any limitations imposed on the resource selections completed in Aurora?

A. Yes. Certain constraints are imposed on the model runs in Aurora for a number of reasons. Some of those reasons include:

- Feasibility of resources that can be selected;
- Timing of resource availability; and
- The amount of excess capacity build permitted.

Q. Explain how constraints are imposed in Aurora due to feasibility of resources that can be selected.

A. The first constraint – imposed on wind expansion -- was applied to capacity expansion in the regional market model (the larger MISO footprint). Particularly during periods in which wind generation resources earned PTC, wind expansion in the regional market was widely selected through year 2024, in excess of 13 gigawatts (GW) of added wind capacity in a single year. The Company conducted research to estimate reasonable amounts of wind capacity that would be added in the region, specifically, the Company reviewed recently-approved projects and projects currently awaiting approval in the MISO transmission queue. Through that research, the Company observed that not more than approximately 5.5 GW of wind is approved per year. Accordingly, optimizations for the MISO footprint were constrained to expansion at 5.5 GW per year.

Q. Explain how the Aurora optimizations are constrained due to timing of resource availability.

A. Some resources require significant construction lead time prior to the commercial operation date (for supply-side resources) or significant lead time to ramp up (for demand-side management programs); therefore, constraints were imposed on the optimization to indicate a "first-year available" for each individual resource option.

- <u>Natural gas</u>: Economic selection of a CT unit can be made as early as year 2023, but a CC unit would not be available for economic selection until 2025, due to the increased lead time for a CC unit;

- Solar: The solar expansion plan approved for the first three years of the 2018 IRP PCA committed the Company to annual competitive solicitations in years 2022, 2023, and 2024; therefore, the first year of section of solar was set as 2025;

- Wind: Economic selection of wind resources can be made as early as year 2023, assuming that the Company could potentially enter into a PPA or a build-transfer agreement by that time;

- Storage: Economic selection of battery storage resources can be made as early as year 2025, assuming that the Company could potentially enter into a PPA or a build-transfer agreement by that time;

- EWR: The Company's EWR Plan filing approved EWR levels of 2% through year 2023; therefore, any expansion of EWR can be added starting in year 2024; and

- Demand Response: Like solar capacity, the 2018 IRP PCA provided for pre-approved levels of demand response. In the 2018 IRP, the Company committed to achieving 607 MW of demand response by 2022; therefore, expansion of DR can be selected starting in year 2023.

Q. Explain how the Aurora optimizations are constrained for the amount of excess capacity built.

A. In order to conduct an optimization for a resource plan, the Company inputs a minimum amount of capacity addition required, as well as a maximum amount allowed. The minimum amount corresponds to the known capacity shortfall, while the maximum is user-defined. If no maximum amount of excess capacity is defined, Aurora may add new resources that are not required to meet customer peak demand. In order to understand the resource mix most optimally selected by Aurora, the Company limited the amount of excess capacity additions by imposing a requirement that no more than 400 MW of surplus capacity is permitted.[10] The value of 400 MW was determined according to the size of available resources in this IRP. A surplus level of up to 400 MW allows unbiased economic

[10] In very few portfolio optimizations, the 400 MW limitation was modified, in order to understand how the resource mix could change, due to differences related to the size of particular expansion resource options.

selection of any resources that are sized 400 MW or less, which includes all resources apart from CC gas units and some of the larger DR blocks. By limiting the amount of excess capacity, the Company is able to identify which resources are selected first to meet precisely specified customer demand levels, within the Aurora optimizations.

SECTION VII: DEVELOPMENT OF DEMAND-SIDE OPTIONS FOR AURORA

Q. What demand-side resources were considered in the Aurora modeling?

A. In addition to the supply-side resources previously mentioned, three demand-side options were included in the Aurora portfolio optimization runs:

1. CVR: This program is explained fully in the direct testimony of Company witness Henry;
2. Increasing levels of DR: An aggregate of multiple different types of DR programs such as smart thermostat programs, capacity bidding, and direct load control were offered in this IRP. More information can be found in the direct testimony of Company witnesses McGraw; and
3. EWR: The Company's base case assumes 2.0% EWR savings growth 2021-2023 and 1.0% cumulative for years 2024-2040. Expansion of EWR savings were offered into the optimization beyond the base case assumption. Further information can be found in the direct testimony of Company witnesses McLean and Lakin Garth.

Conservation Voltage Reduction

Q. Please describe the CVR Program offered into Aurora.

A. As explained in the direct testimony of Company witness Henry, CVR is a program that offers both an energy and peak demand benefit. To model this program in Aurora, projected MWh (energy) and MW (peak demand) reductions were provided to Company witness Breuring to incorporate into the load forecast. The levels of CVR included in the load forecast are summarized by Company witness Henry and presented in Exhibit A-86 (MSH-1).

As presented in the direct testimony of Company witness Henry, the CVR Program requires advanced ramping in order to achieve material peak demand reductions, starting with investments as well as MWh and MW reduction benefits in 2019. In 2021, the program is expected to provide approximately 20 MW of peak load reduction. For each subsequent year, an additional 10 to 11 MW of peak load reduction is expected, until year 2030, when the program's peak MW reduction occurs at 113 MW. The costs of the program are discussed in the direct testimony of Company witness Henry.

The first year in which resource selection begins under any scenario or sensitivity is 2023; but in Aurora optimizations, the CVR Program is assumed to begin in 2020 regardless, in order to achieve the maximum levels of peak demand reductions by the time resource optimization begins. The CVR Program, therefore, was "locked in" to the resource selections for the following reasons:

- A build plan excluding CVR, instead allowing selection of the next least-cost resource available, resulted in higher NPV costs in each scenario base case; and
- Aurora would not allow economic selection of a resource in 2020 if no capacity need exists in that year.

Q. Please explain Exhibit A-9 (STW-6).

A. Exhibit A-9 (STW-6), lines 1 through 6, column (b), provides the economic benefit of allowing the CVR Program to begin a ramp up starting in 2020, even if the capacity need does not require it (the comparison was taken to the base case sensitivity in each scenario). A negative value represents projected customer *savings* from an NPV perspective of including CVR in the portfolio, as opposed to selection of other resources. The only instances in which CVR does not provide savings is in the EP scenario under the AEO gas price outlook. In this scenario, when CVR was removed from the portfolio of resources, selection of storage to replace the CVR resulted in avoiding a fixed-sized DR program.

The "right-sizing" of storage resources in the sensitivity with no CVR was ultimately a slightly lower-cost option for customers. Clearly, there are limited and specific scenarios where CVR is not an economic choice for customers; in this case, the inflexibility of an aggregate DR program. In each of the other five scenarios, however, Exhibit A-9 (STW-6) projects significant customer savings with the inclusion of CVR as part of the portfolio. The favorable economics presented in this exhibit represent the costs of CVR, including with a shared savings incentive mechanism, compared to other resource alternatives offered in this IRP. Additional discussion of a CVR incentive mechanism is provided in the testimony of Company witness VanSumeren.

<u>Demand Response</u>

Q. Please describe the source of DR programs offered into Aurora.

A. The Company expects to provide approximately 607 MW of DR reductions by 2022. Expansion beyond 2022 levels were evaluated in this IRP, based on both the 2017 DR potential study conducted by AEG ("AEG DR potential study") as well the Company's own 2020 potential study ("CE DR potential study").

Q. Please describe the DR program offered into AEO gas scenario optimizations, based on the AEG DR potential study.

A. The DR aggregate resources offered to Aurora in this IRP were developed based on an allocation of the total potential determined in the AEG DR potential study to Consumers Energy's service territory. The direct testimony of Company witness Robert L. Fratto, in the Company's 2018 IRP filing, MPSC Case No. U-20165, describes the allocation of the DR potential from the AEG DR potential study to Consumers Energy and the DR cost assumptions in the AEG DR potential study.

Similar to the approach taken in Case No. U-20165, a "low" and a "high" prototype were developed from the AEG DR potential study for selection in this IRP. The "low" prototype provided for a total of approximately 1,200 MW of DR expansion, or about 600 MW above and beyond the Company's 2022 target. The "low" prototype was offered into the BAU AEO scenario. The "high" prototype, which was offered into the EP AEO and ET AEO scenarios, provided for nearly 1,800 MW of total DR expansion, or approximately 1,200 MW above and beyond the 2022 target.

For modeling purposes, all costs associated with incremental DR are assumed to be O&M-related. In reality, there will be some capital investments required to achieve the levels offered in the various portfolio optimizations. Costs for DR were offered into Aurora on a levelized cost basis, with two separate blocks for the "low" prototype, applicable to the BAU AEO scenario, starting at $53/kW-year (2020 dollars) and the second at $64/kW-year, both escalating at 2% each year. In the EP AEO scenario, three "high" prototype blocks were offered; the first block started at a levelized cost of $57/kW-year, the second at $67/kW-year, and the third at $76/kW-year, all three escalating at 2% per year. Finally, in the ET AEO scenarios, a reduction of DR costs at 35% lower than BAU is required. This resulted in the three "high" prototype blocks in ET AEO corresponding to levelized costs of $37/kW-year, $44/kW-year, and $49/kW-year, respectively. The basis for offering the higher levels into ET AEO and EP AEO is that those are the worlds in which advances in technologies are coupled with potentially higher energy prices, which could result in increased customer interest in DR, resulting in higher levels of DR compared to what is currently considered a reasonable amount of reliance.

Exhibit A-10 (STW-7) presents a graphical presentation of the levels of DR offered into each scenario and the corresponding size of the programs Aurora was able to select. Page 1 shows the two DR blocks offered into the BAU AEO scenario; and page 2 shows the block offered into ET AEO and EP AEO.

Q. Please describe the DR program offered into the Consumers Eneregy gas scenarios, based on the Company's own potential study.

A. The aggregate DR resource offered into Consumers Energy scenarios (BAU CE, ET CE and EP CE) was developed based on data extracted from the 2020 DR potential study conducted by Demand Side Analytics. Details of that study are provided in the direct testimony of Company witness McGraw. The study projects a total potential of approximately 1,088 MW of total DR, or about 480 MW above and beyond the 2022 levels. Each of the three Consumers Energy scenarios mentioned above were evaluated with the full potential offered for selection.

In the Aurora selection simulations, the 480 MW of incremental DR was allowed to be selected in six different blocks or "tranches." (See Exhibit A-10 (STW-7)). Each tranche corresponds to an incremental cost increase, such that a certain amount of DR was available at a given price, and for Aurora to add more DR, the next tranche would come at a higher price. In this way, the model can add incrementally higher levels of DR, until the resource is no longer economical. The CE scenario tranches were on average 45 MW each, in size,[11] with the lowest cost tranche offered in at a levelized cost (in 2021 dollars) of $75 per kilowatt-year, increasing by $10 per kilowatt, to $115 per kilowatt-year for the fifth tranche, and the sixth and final tranche priced at the weighted average of the highest

[11] The exception to this average size of the DR blocks is the last block, which was an aggregate of all DR above $120/kW-year (2021 levelized dollars)

cost programs - $166 per kilowatt-year. Page 3 of Exhibit A-10 (STW-7) presents the amounts of DR available at the increasing costs, up to the total of all six tranches.

The operating parameters modeled for DR assume that any incremental amounts picked will be operated as an aggregate resource, with an ability to call upon the resource to meet customer demand no more than forty hours per year. Sensitivities were performed in both the Company's capacity sufficiency analysis as well as risk analysis to evaluate the impacts on both customer cost as well as electric supply reliability. These sensitivities were an investigation to determine the impact to customer costs and supply reliability if DR was only available ten hours per year as well as if DR did not respond when called upon at all – effectively, if DR was available zero hours per year. The selection of which 10 or 40 hours per year to call upon DR was made within Aurora's long-term capacity expansion or zonal simulations, based on the highest demand hours, while considering generating resource unit operating constraints.

Q. How does the resource plan for DR in the PCA compare to the portfolio optimizations results from Aurora?

A. In many of the scenarios and sensitivities under both DR potential studies, DR was selected in the LTCE simulations in discreet blocks, based on the price-based tranches described above. In some cases, large amounts of DR programs were selected in specific years, based on capacity need timing. However, as discussed in Section V, above, the LTCE model results were used to give an indication of what *types* of resources provided the lowest cost to customers, and with timing of the additions to a lesser degree. In fact, in many optimization portfolios, DR was added incrementally over time to capture a realistic and feasible expansion of customer-driven programs. Specifically, the additions of DR included in the glide path portfolios discussed in Section VIII and in the PCA provide a gradual ramp of DR over a number of years. This approach affords the Company the flexibility to carefully implement DR in the most efficient way for customers. As DR grows within the state of Michigan, the Company's PCA offers scalability based on its experience with operation of DR as a large-scale capacity resource and adaptability to any potential changes to the treatment of DR as a capacity resource within the MISO regional markets.

The selection of DR, as presented in the PCA, corresponds to incremental additions above 2022 levels. This plan represents contribution to the PRMR from DR of approximately 10%. The validity and reasonability of the 10% share of capacity requirements is supported in the testimony of Company witness McGraw.

Energy Waste Reduction

Q. Please describe the EWR programs offered into Aurora.

A. A variety of increasing levels of EWR savings were evaluated for expansion in this IRP. In all scenarios, and per the EWR filings made in MPSC Case No. U-20372, the Company will achieve EWR reductions of 2.0% of prior year sales 2021-2023. Below are the levels considered in the various scenarios and sensitivities included in this IRP for the remainder of the study period:

- The Consumers Energy scenario base case assumes 1.0% cumulative EWR savings growth for years 2024-2040.
    - Expansion up to levels identified in the 2020 EWR potential study was offered as a prototype for selection in all Consumers Energy scenarios. Additional details regarding the potential study and proposed expansion of base case EWR can be found in the direct testimony of Company witness Steven Q. McLean.
- The MPSC scenario base case assumes 1.5% cumulative EWR savings growth for years 2024-2040.

  - Expansion to 2.0% for years 2024-2040 was offered as a prototype for selection in most MPSC scenarios;
  - Expansion of an incremental 0.25% for years 2031-2040 (for a total of 2.25% for years 2031-2040) was also offered as a prototype for selection in most MPSC scenarios.

- A sensitivity of EWR is included in each of the MPSC sensitivities:
  - Expansion of EWR to 2.5% over four years and remaining at that growth level throughout the study period.

Like the CVR Program, EWR expansions selected by the model are assumed to begin in 2024 regardless of the first year of capacity need. This allows EWR to deliver higher levels of peak demand reductions to fill significant capacity shortfalls. Therefore, similar to the CVR option, EWR expansions were "locked in" to the optimization selections for the following reasons:

- The LCOE, shown in Exhibit A-7 (STW-4) for EWR is relatively competitive with other resources;
- EWR provides a significant amount of energy reduction; using terms applicable to supply-side resources, EWR has a 75-80% capacity factor, providing material energy *value*;
- Exclusion of EWR, in lieu of other available supply and demand-side resources was evaluated as an LTCE simulation in Consumers Energy scenarios and shown to both increase and decrease NPV costs in the three scenarios evaluated, indicating EWR as a relatively marginal resource compared with the alternatives; and
- Aurora would not allow economic selection of a resource in 2024 if no capacity need exists in that year.

Q. Please discuss how the economic evaluation of EWR is presented in Exhibit A-9 (STW-6).

A. Exhibit A-9 (STW-6), lines 1, 3, and 5 in column (c), provide the economic benefit of locking in the EWR Program starting in 2024 versus excluding the expansion. A negative value represents projected customer savings from an NPV perspective by the inclusion of

EWR. In this IRP, the Company seeks approval of the expansion of EWR according to the Consumers Energy 2020 EWR potential study (and not the 2017 potential study); therefore, the economics of the EWR prototypes included in MPSC scenarios were not evaluated.

Q. Company witness McLean discusses an update made to the EWR forecasts included in modeling. Please explain how these updates were handled.

A. As discussed in the testimony of Company witness McLean, the EWR forecast was updated late in the modeling process. The update resulted in significant reductions in projected customer costs due to substantial increases in the benefits that the EWR expansion programs would provide. Specifically, the original EWR outlooks included in the modeling materially understated both the peak demand reductions and avoided annual generation requirements resulting from both base levels and expansion of EWR. Since this update was identified late in the modeling process, it was not feasible to update most of the scenario and sensitivity modeling. Instead, the update to the EWR base levels and expansions in the Consumers Energy scenarios were included in the modeling of the PCA and alternate plan. A new load forecast was input to Aurora, resulting in a reduction of resources necessary to meet the PRMR in the PCA and alternate plan.

Q. How does the resource plan for EWR in the PCA compare to the portfolio optimizations results from Aurora?

A. The PCA includes expansion of EWR up to the levels identified in the Consumers Energy 2020 EWR potential study. EWR is proposed to continue its expansion to nearly 2% of prior year sales through the 2020s; beyond 2030, the study identifies potential levels only achieving approximately 1% cumulative of prior year sales in the remaining years of the study period.

SECTION VIII: OPTIMIZATION PORTFOLIOS

Q. In Section V of your testimony, you explained that combinations of resources are offered into the Aurora model for selection. Please explain how these combinations are designed, prior to Aurora resource selections.

A. The term "design" is in reference to how the various portfolios were constructed for optimization modeling within Aurora. The design process encompasses some of the modeling constraints that may be input to Aurora in order to obtain a particular type of portfolio resource mix. For example, to develop one portfolio design that considers the addition of new peaking capacity only, constraints were entered into the Aurora model to prevent the optimization logic from adding any new resource options other than new gas-fueled simple cycle CTs. Similarly, some modeling constraints were "loosened" in order to evaluate other portfolio designs. Examples of the types of parameters that were varied with the construction of different portfolio designs include: resources available for selection, maximum reserve margin requirement, and minimum or maximum allowable numbers of a resource to be built in a given year or throughout the planning period.

Q. What are the portfolio designs that were considered in this IRP?

A. A total of ten portfolio designs included in the Aurora optimizations are presented in Exhibit A-11 (STW-8). Portfolios 1, 2, and 3 were evaluated in nearly all sensitivities; however, there were some sensitivities for which some of the three of those portfolios were not necessary, and the NPV result is not presented in Exhibit A-12 (STW-9), discussed later in this direct testimony.

- The first portfolio design, referred to as <u>Portfolio 1</u>, is a portfolio mentioned in Section VI of this direct testimony as the hypothetical capacity replacement in which other MISO market participants may have capacity available for sale from existing and new generating facilities. Portfolio 1 represents a portfolio in which all required incremental capacity can be purchased on a short-term or spot basis at a forecasted market capacity price. The market price of capacity is assumed to be 75% of CONE. With this particular portfolio design, there is effectively only one resource option for each scenario and sensitivity case, the market purchase of ZRCs. The revenue requirements include the spot market capacity expense and the spot market energy expense for all economy energy purchases.

- A second portfolio design, <u>Portfolio 2</u>, represents a scenario in which Aurora may select any and all supply or demand-side resources to meet the Company's demand and reserve margin requirements. Given the variety of technologies available and the period being studied, multiple resource plans are generated and each resource plan is ranked by the corresponding NPV. In some scenarios, Portfolio 1 may provide a lower revenue requirement than Portfolio 2. In other scenarios, the opposite outcome may result, depending on the relative cost of available supply- or demand-side resources versus the assumed cost of market purchases. In general, the more options offered to the Aurora optimization, the lower the NPV cost. Since Portfolio 2 offers all supply- and demand-side options in the optimization, it can be considered the full optimization performed on each scenario and sensitivity; however, in this portfolio, the long-term capacity expansion simulation results in a resource plan that assumes an "overnight build" of resources. For an illustrative example, consider an LTCE simulation on a sensitivity in which there is no capacity need until 2030; the LTCE would likely add no resources until selecting, perhaps, 3,000 MW of solar to be brought online "overnight" in a single year, 2030.

- <u>Portfolio 3</u> is referred to as the "glide path" portfolio design and results in what is later referred to as the "optimal plan" of any given scenario or sensitivity. Upon completion of the LTCE simulation in Aurora, which is provided by Portfolio 2, a glide path optimization portfolio was created post-processing and evaluated as a zonal run in Aurora. A zonal run differs from an LTCE run in that a zonal run is not *selecting* new resources like an LTCE does. Instead, a zonal run will perform a production cost simulation on a completed selection of resources, already sufficient to meet peak demand plus required reserve margins. As discussed in Section VI of this direct testimony, as well as in the testimony of Company witnesses Battaglia and McGraw, many of the resources included in this IRP require significant lead time and/or may be limited by feasibility constraints. Examples include the lead time required to enroll customers in demand response programs in order to provide a significant amount of zonal resource credits to serve the PRMR, or the feasibility limitations of adding gigawatts of solar capacity in a single year. In the glide path portfolio, resources are added incrementally, over a number of years, to ensure that when needed and selected in the LTCE, the resources provide sufficient ZRC to enable retirement of an existing resource or expiration of a PPA. This "glide path" of incremental addition of supply capacity or growth of a program over time means that resources may be added prior to the year of need. Development of the glide path is completed in Excel and is based on the outputs of the LTCE. The glide path would consider all resources selected, and apply feasibility constraints. Returning to the illustrative example discussed above, instead of waiting until 2030 to add solar resources, the glide path optimization portfolio will begin adding solar capacity as soon as possible, 2025, in this case, and ramp up the solar capacity additions steadily over time – 500 MW each year through 2030, to meet the required 3,000 MW target. Portfolio 3, the glide path portfolio, is the basis of all economic comparisons presented for all scenarios and sensitivities in this IRP. Economic results presented throughout this IRP regarding economic analyses generally represent the difference between the NPV of the glide path optimization portfolio of a given sensitivity versus the NPV of the glide path optimization portfolio for the base case in that scenario.

- Portfolio 4 is the Company's preferred plan, or PCA. The PCA is described in detail in the direct testimony of Company witness Blumenstock and is also discussed in Section X of this direct testimony, from a modeling perspective. The PCA can also be reviewed in Exhibit A-14 (STW-11). The PCA is a glide path portfolio, but is a specific fixed capacity replacement portfolio, meaning once the resource selection was determined, the resources were locked into the Aurora simulations for evaluation as zonal runs. In Exhibit A-11 (STW-8), lines 4 through 10, columns (e) and (f) are checked off for the PCA, indicating what type of portfolio the PCA is – it is not an LTCE, it includes no market purchases; it's a glide path portfolio that can be *fixed* for evaluation in many scenarios or sensitivities. The PCA was evaluated on all MPSC-required sensitivities and on all base scenarios for which it provided sufficient resources. That is, since the PCA is a fixed portfolio of resources, in some cases, those resources would be insufficient to meet the PRMR of a given sensitivity and, therefore, there it is not reasonable to evaluate Portfolio 4 on that sensitivity. Specifically, Portfolio 4 was evaluated on nine sensitivities: the retirement base case of all seven scenarios, not including AT (which has a different PRMR) as well as the high gas price sensitivities included in BAU AEO, ET AEO and EP AEO.

- Portfolios 5 through 10 were developed as part of the Company's risk assessment and are each glide path portfolios as well as fixed portfolios, as indicated in columns (e) and (f) in Exhibit A-11 (STW-8). Portfolio 5 represents the optimal portfolio (Portfolio 3) from the BAU CE retirement base case sensitivity. As explained in the testimony of Company witness Munie, the optimal plan from each scenario was evaluated under the remaining two scenarios for which the resource plan meets the PRMR. Table 2 of Exhibit A-11 (STW-8) presents a visual tally of these optimal portfolio evaluations. Portfolio 5, the BAU CE optimal plan was evaluated under ET CE and EP CE scenarios, as checked on line 12 in columns (d) and (e).

- Likewise, Portfolio 6 represents the optimal portfolio from the ET CE retirement base case sensitivity and was evaluated on the retirement base case in BAU CE and EP CE (see line 13, with checks included in columns (c) and (e)).

- Portfolio 7 is the optimal portfolio from the EP CE retirement base case sensitivity and evaluated on the retirement base case in BAU CE and ET CE (see line 14 columns (c) and (d)).

- Portfolio 8 is the optimal portfolio from the BAU AEO retirement base case sensitivity and evaluated on the retirement base case in ET AEO and EP AEO (line 15 columns (g) and (h)).

- Portfolio 9 is the optimal portfolio from the ET AEO retirement base case sensitivity and evaluated on the retirement base case in BAU AEO and EP AEO (line 16 columns (f) and (h)).

- Finally, Portfolio 10 is the optimal portfolio from the EP AEO retirement base case sensitivity and evaluated on the retirement base case in BAU AEO and ET AEO (line 17 columns (f) and (g)).

The Alternate Plan was not included as an optimization portfolio, but is included as Portfolio 3 under a BAU CE sensitivity. A dedicated portfolio was not created, as was done for the PCA because the Company is not seeking approval to execute the alternate plan and therefore did not evaluate it across all applicable scenarios and sensitivities.

Q. Is the mix of resources selected for a given portfolio design the same across all scenarios and sensitivities?

A. For fixed portfolios, Portfolios 4 through 10, yes, the resource mixes will be the exact same in those optimization portfolios for all scenarios and sensitivities. Those resource mix selections are provided in graphical format in Exhibit A-14 (STW-11).

Portfolio 1, in which capacity and energy market purchases are made to meet customer demand, may vary in certain sensitivities. For all AEO gas scenarios and sensitivities except the 1.5% load growth, 50% ROA Return, and 2.5% EWR Growth sensitivities, Portfolio 1 will be the same. That is, the amounts of purchased capacity from the market is the same for all scenarios and sensitivities not listed. For Consumers Energy gas scenarios, particularly sensitivities evaluating early retirement of existing assets, different amounts of purchased capacity are needed to meet customer demand.

For Portfolios 2 and 3, the resource plan selected will likely not be the same across all scenarios and sensitivities. The combination or set of resources offered into the optimization was generally preserved across all scenarios and sensitivities. However, for a given portfolio design, the resulting resource plan or mix (e.g., timing, technology, amounts) will likely differ from scenario to scenario as a result of differences in input assumptions for each scenario. For example, Portfolios 2 and 3 would likely include a greater number of new gas-fueled capacity additions added through year 2040 in the BAU CE gas scenario than in the BAU AEO gas scenario due to substantially higher gas prices in the AEO gas scenario, which makes gas-fueled generation much less economic. In this example, while resources offered (e.g., timing, technology, and amounts) is the same for both scenarios, the selection of and amounts of new gas-fueled generation added are different. For the same reasons mentioned above, we would reasonably expect for a given portfolio design, the NPVs will vary for each of the different scenarios and sensitivities.

<u>SECTION IX: PURCHASED GAS UNIT OPERATIONS</u>

Q. The Company's PCA requests approval of the purchase of two natural gas asset groupings, offered through a request for proposals ("RFP") process described in the testimony of Company witness Troyer. What information regarding those natural gas assets are you discussing in your testimony?

A. I will discuss the operating characteristics and projected generation of the natural gas assets, as modeled in this IRP. I will present information in exhibits for the total annual average cost of the units; availability factors (scheduled and forced outage rates); type of operation cycle; hours of operation projected per year; projected start-ups per year; cycling conditions per year; and annual heat rates based on projected operation.

Q. What are the specific natural gas-fueled generating units included in your testimony?

A. As introduced in the testimonies of Company witnesses Blumenstock and Troyer, I will be discussing the parameters identified above for the following generating units: the Covert combined cycle gas plant, the Dearborn Industrial Generation ("DIG") combined cycle and peaking units, the Kalamazoo River Generating Station peaking plant, and the Livingston Generating Station peaking plant.

Q. What are the assumed operating characteristics of the aforementioned units?

A. The operating characteristics are summarized for each gas unit in Exhibit A-15 (STW-12) on pages 1 through 4. Information provided in this exhibit includes maximum capacity, minimum capacity, summer capacity derations, ZRCs, type of operation cycle, scheduled outage rates, forced outage rates, variable operating and maintenance costs included in dispatch, input heat rates as various dispatch blocks, as applicable, and emission rates.

Q. What are the forecasted levels of operation for the gas units?

A. Page 5 of Exhibit A-15 (STW-12) provides projected output generation in megawatt hours ("MWh") on lines 1 through 15, projected hours of operation on lines 16 through 30, and projected capacity factors on lines 31 through 45. Page 6 summarizes the resulting annual average costs[12] of the plants on a dollar per MWh basis on lines 1 through 4, with the underlying delivered fuel costs on lines 5 through 9. Page 7 provides the projected number of start-ups per year on lines 1 through 15 and the resulting net heat rates on lines 16 through 30, based on the projected output of the plants.

[12] Annual average costs provided in this exhibit include fuel costs, start-up costs, emissions costs, variable operating costs, fixed operating costs and on-going capital.

The total annual average costs provided in Exhibit A-15 (STW-12), page 6, were calculated based on the fuel costs presented in the direct testimony of Company witness Gallaway and based on the fixed and variable operating costs found in the direct testimony of Company witness Kapala.

<u>SECTION X: SUMMARY OF MODELING RESULTS</u>

Q. Please explain how the IRP results are summarized.

A. Results of the Aurora modeling are provided in three exhibits.

- Exhibit A-12 (STW-9) provides the NPV economic results of the multitude of scenarios, sensitivities, and portfolios;
- Exhibit A-13 (STW-10) demonstrates the amounts and timing of each *type* of new technology resources selected amongst the multitude of scenarios, sensitivities, and portfolios; and
- Exhibit A-14 (STW-11) provides a graphical summary specific to the exact amounts, timing, and types of new technology resource selections in each of the eight scenarios, under the retirement base case assumptions and with the addition of the proposed purchase of natural gas capacity. This exhibit also includes the details of resources included in the PCA and alternate plan.

<u>NPV Economic Results</u>

Q. Please discuss how the NPV economic results are summarized.

A. The NPV results are summarized by comparing the economics of the multiple portfolios defined in Section VIII of this direct testimony. As outlined above, eight future scenarios and multiple sensitivities were evaluated for a combined total of 86 scenarios and sensitivities in the IRP using Aurora. For most scenarios and sensitivities, Portfolios 1 through 3 were constructed and considered to assess the relative economics and risks of different resource combinations, timing, and amounts. As discussed in Section VIII, Exhibit A-11 (STW-8) provides a summary of the ten portfolio designs.

Q. What are the NPV results of the IRP scenario modeling?

A. The results of the IRP scenario modeling are presented in Exhibit A-12 (STW-9). This exhibit provides NPV costs (in millions of dollars) for whichever of the ten portfolio options that were applicable to meet the Company's capacity needs between 2020 through 2040.

Page 1 of Exhibit A-12 (STW-9) contains results for Portfolios 1 through 7 on lines 1 through 7 for all sensitivities evaluated under BAU CE Gas scenario. Each of those sensitivities is listed in columns (a) through (p). Beginning on line 8, the delta for each sensitivity is calculated as the difference between the NPV result of the sensitivity minus the NPV result of the base case, found in column (a). This difference is taken for each portfolio. For example, consider column (d), lines 8 through 10. Column (d) line 8 represents the difference between the Portfolio 1 NPV result of the Campbell 1 2026 retirement sensitivity and the Portfolio 1 NPV result of the base case; line 9 represents the difference between the Portfolio 2 NPV result of the Campbell 1 2026 retirement sensitivity and the Portfolio 2 NPV result of the base case; and so on. Page 2 provides similar information under the ET CE Gas scenario; and Page 3 provides similar information under the EP CE Gas scenario. While most columns on lines 8 through 10of these three pages provide the delta to the base case, there is an exception, which occurs in columns (o) and (p). Column (o) contains no deltas; column (p), line 10 calculates the difference of the final retirement base case compared to column (o), line 3, which contains the NPV result of the alternate plan.

Similar information is presented on pages 3 through 6 for NPV results and deltas under the AEO gas scenarios. Page 4 presents NPV results and deltas for all sensitivities evaluated on the BAU AEO Gas scenario; page 5 includes NPV results and deltas for sensitivities evaluated on the ET AEO Gas scenario; and page 6 includes NPV results and deltas for the EP AEO Gas scenario. Note that Portfolios 1 through 4 are included on pages 4 through 6, but portfolios 5 through 7 are not; instead, Portfolios 8 through 10 are included on lines 5 through 7. That is because Portfolios 5 through 7 were not evaluated on MPSC scenarios and sensitivities since the optimal plans corresponding to those portfolios were not applicable to meet the PRMR of the MPSC scenarios and sensitivities. Likewise, Portfolios 8 through 10 were not applicable for CE scenarios and sensitivities.

Page 7 of Exhibit A-12 (STW-9) includes just two sensitivities evaluated under the AT scenario. These are shown in columns (a) and (b), with Portfolios 1 through 4 results and deltas listed on lines 1 through 4 and 5 through 8. The PRMR of AT scenarios and sensitivities was significantly different than any other scenarios; therefore, no additional portfolios were evaluated on AT scenarios and sensitivities.

Finally, page 8 of Exhibit A-12 (STW-9) provides results for the single sensitivity evaluated within the Carbon Reduction scenario. This sensitivity only includes results for Portfolios 1, 2, and 3, shown on lines 1 through 3. For comparison purposes, the retirement base case sensitivity under EP AEO assumptions is included; lines 5 and 6, column (b) provides the cost increases associated with the 1.5% load growth assumption.

The NPV values presented on pages 1 through 8 of Exhibit A-12 (STW-9) correspond to results assuming excess capacity can be sold to reduce customer costs at a capacity price of 75% of CONE. In reality, the Company acknowledges the long-term value of capacity will likely vary, potentially from year-to-year. Furthermore, when making decisions with these NPV results included in consideration, the Company acknowledges the risk of natural gas price variability as well. Therefore, results of the sensitivities presented in Exhibit A-12 (STW-9) were evaluated across a range of potential gas prices and capacity prices. In this way, the Company considers not just a discreet NPV result and corresponding delta of a given sensitivity, but instead, can understand the *range* of possible outcomes, given the unpredictable nature of both natural gas and capacity price outcomes. Because these ranges of NPV values support the decisions included in the Company's PCA, which are discussed in the direct testimony of Company witness Blumenstock, the graphical results of the gas and capacity NPV result deltas to the base case are found in Figures 9 and 10 in the direct testimony of Company witness Blumenstock. Figure 9 presents the difference in the Portfolio 3 NPV result of each retirement sensitivity and the Portfolio 3 NPV result of the base case. The range of NPV values are shown in green shading if the difference is negative, resulting in customer *savings* compared to base; or in red shading if the difference is positive, resulting in *increasing* customer costs compared to base. In total, there are twenty NPV data points included in these ranges: an NPV value for four different gas prices (25% below base gas price, base gas price, 25% above, and 50% above) and five different capacity prices (0% CONE, 25%, 50%, 75%, and 100% CONE). A discreet NPV value is called out in the figure that corresponds to the NPV at base gas prices and at both 0% CONE and 75% CONE. There are also bars, or "whiskers," included within the bars of the figure, which correspond to the range of NPVs resulting from the *gas price sensitivities* performed at each capacity price step indicated. Figure 10 in the testimony of witness Blumenstock makes a similar comparison of the PCA to the alternate plan.

Q. Please discuss any significant observations of the results of the sensitivities listed in Exhibit A-12 (STW-9).

A. A few significant observations of the sensitivity modeling are as follows:

- Pages 1 through 3 of Exhibit A-12 (STW-9) provide the results of the Consumers Energy unit retirement analyses assuming surplus capacity is sold at 75% CONE; however, further discussion and the more robust NPV results (including natural gas and capacity price sensitivities) are presented as figures in the direct testimony of Company witness Blumenstock. Because many of the deltas shown on pages 1 through 3, line 12 of Exhibit A-12 (STW-9) are negative, the Company recognized the potential for customer savings under an accelerated retirement of one more Campbell units.

- Columns (o) and (p) on page 1 through 3 present the NPVs associated with retirement decisions corresponding to the alternate plan and retirement base case under Consumers Energy scenario assumptions.

- Pages 4 through 6 provide the results of the MPSC scenarios and sensitivities. Column (a) of each of the three pages includes the base case NPV results under the MPSC scenarios described in Section IV of this direct testimony. In column (b), the economics of the retirement decision associated with the alternate plan is presented on each page, with results included in columns (c) through (g) on page 4 and columns (c) through (f) on pages 5 and 6 for the remaining MPSC sensitivities (under the alternate plan retirement assumptions).

- Column (h) on page 4 and column (g) on pages 5 and 6 present the NPV results of the retirement base case under MPSC scenarios. The deltas in MPSC scenarios are generally unfavorable for the retirement base case because of the higher natural gas price forecast assumed in MPSC scenarios.

- Finally, columns (i) through (m) on page 4 and columns (h) through (k) on pages 5 and 6 provide NPV results, under retirement base case assumptions, for the remaining MPSC sensitivities. These results are discussed below.

- The 1.5% load growth sensitivities on the three scenarios – BAU AEO, EP AEO, and ET AEO evaluate the risk of high load growth on these scenarios. The results generally indicate that compared with the base case, the glide path portfolios are approximately $2.5 billion more expensive (line 10, column (i) on page 4, column (h) on pages 5 and 6); meaning that if load grew at 1.5% per year, customer costs on an NPV basis would increase by approximately $2.5 billion. Under BAU AEO assumptions, the high load growth assumptions require the addition of new CT capacity and higher levels of DR, while ET AEO and EP AEO scenarios generally increased the amount of solar and DR.

- The 2.5% EWR sensitivity for the three scenarios evaluates the impact of a significant growth in EWR savings over a relatively short period of time. The results indicate that compared with the base case, if EWR levels were achieved and maintained at 2.5% starting in 2021, under retirement base case assumptions, customer costs would decrease by between approximately $550 million and $750 million NPV compared with the base (glide path portfolio versus glide path portfolio). With greater contributions to serving the PRMR made by EWR, solar expansion declines in BAU AEO and ET AEO; in the EP AEO scenario, the reduction in selection of solar is significant, with replacement of DR in lieu of solar.

- Exhibit A-12 (STW-9) column (l) on page 4 and column (k) on pages 5 and 6 presents the results of the sensitivity evaluating the impacts of increasing AEO gas prices to two times base gas prices by the end of the planning period for all three scenarios. The results indicate that if gas prices increased to 200% of AEO base gas prices by 2040, the glide path portfolios would increase by between $1.5 billion and $2.2 billion NPV compared with retirement base case glide path portfolios. The Company sees the gas prices in this sensitivity as falling outside the range of reasonable possibilities;

- Page 4, column (j) of Exhibit A-12 (STW-9) presents the results of the sensitivity that evaluate impacts due to return to bundled service of 50% of customers currently taking service from an alternative energy supplier. Under this sensitivity, additional capacity and energy needs would be required, compared to the retirement base case, which would increase costs by approximately $1 billion in the glide path portfolios. The higher PRMR would require more resources, and the Aurora selected plan in this sensitivity chose additional solar and storage to make up the higher shortfalls.

- Page 4, column (m) of Exhibit A-12 (STW-9) presents the results of the sensitivity that evaluated filling future capacity needs with only CTs. If the resource mix was limited to expansion with only CT resources, NPV costs would increase by $365 million compared to the retirement base case glide path portfolio.

- Exhibit A-12 (STW-9), page 5, column (i) presents the results of the sensitivity that evaluated an increased renewable portfolio standard to 25% by 2030, under the ET scenario. However, the Company's retirement base case sensitivity already achieves this target; therefore, there is no NPV delta for this sensitivity versus the retirement base case glide path portfolio.

- Page 6, column (l) of Exhibit A-12 (STW-9) presents the results of the sensitivity that evaluated a reduction of CO_2 emissions of 50% by year 2030, under the EP scenario. Once again, the retirement base case glide path portfolio achieved this goal, therefore, there is no NPV delta for this sensitivity.

- On page 7, NPV results under AT scenario assumptions are presented for the retirement base case. In this scenario, the addition of the existing natural gas assets is offsetting the addition of distribution-connected solar and battery storage, which is assumed at 50% below BAU costs. Under such dramatic reductions in capital costs for these resources, the displacement by the gas units results in a $578 million NPV increase.

- Finally, page 8 of Exhibit A-12 (STW-9) presents the NPV results of the Carbon Reduction scenario. This scenario is loosely based on the EP AEO scenario, with the addition of a high load growth assumption, a 28% CO2 reduction target by 2025 (compared with 2005 levels) as well as a 32% CO2 reduction target by 2025. The Company's retirement base case sensitivity achieves both of these CO2 reduction goals, therefore column (a) on page 8 matches exactly with column (g) on page 6. Column (b) of page 8 includes the high load growth assumption as well as the final requirement of the Carbon Reduction scenario, which is to include the PCA as the starting point of the capacity replacement plan. Due to the high load growth assumption, additional resources were required to meet the PRMR; Aurora selected additional solar and storage to fill the higher shortfalls. Customer costs under these assumptions increase by $1.4 billion compared to the retirement base case.

Q. Are there any additional sensitivity results you will discuss in your testimony?

A. Yes. The final set of sensitivity analyses discussed in this testimony include qualitative observations from sensitivities evaluating: 1) the Company's assumed discount rate; 2) the impacts of changes to solar ELCC; and the 3) resource selection changes due to higher transmission network upgrade costs.

Q. Please discuss the results of the sensitivity evaluating an alternate discount rate.

A. The first sensitivity evaluates impacts on changes to the Company's assumed discount rate. Specifically, a rate of 2.5% was evaluated, compared to the base assumption of 7.5%. The scope of this analysis included the impact to net present value results, particularly the *delta* of NPVs, which are the primary metrics for the economic analyses used in this IRP. The analysis did not include identification of different resource selections under an alternate discount rate, nor did it consider impacts to customer rates or revenue requirements, or utility financials.

The primary observations from the analysis are that: 1) a lower discount rate will increase the total NPV of a portfolio of resources as future year costs are discounted less; 2) a lower discount rate may improve the economic outlook of some new technology resources or customer programs when evaluated in isolation (for example, the levelized cost of energy of the resource could be lower under the lower discount rate); and 3) the magnitude of the delta of NPVs between two sensitivities will likely grow under a lower discount rate (for example, projected savings of an accelerated retirement sensitivity versus base will likely be greater at a 2.5% discount rate versus a 7.5% discount rate).

The Company's interpretation of these observations is that a lower discount rate would appear to result in no changes to the set of decisions that are included in the PCA. Another important observation is that utilization of a lower discount rate in NPV analysis ascribes a greater value to projected customer savings that will be experienced by future customers when compared to NPV analysis utilizing a higher discount rate, which would ascribe more value to near-term savings.

Q. Please discuss the results of the sensitivity evaluating an alternate assumption of solar ELCC.

A. The MISO publishes an effective load carrying capability value of 50% for new solar capacity (without sufficient historical performance data on which to support the ELCC). However, the potential reduction in ELCC, as solar capacity expansion continues, has been discussed in various stakeholder forums at the MISO. Therefore, the Company has conducted a sensitivity that evaluates the change in resource selections when the solar ELCC gradually declines from current levels of 50% to 30% by 2033. As solar's installed capacity provides for fewer and fewer ZRC to contribute to serving the PRMR, increasing amounts of solar capacity are added (approximately 1,500 MW of additional solar by the end of the study period) as well as significant increases in the addition of battery storage resources (approximately 1,000 MW of additional storage by the end of the study period). The additional solar and storage capacity required comes at an NPV customer cost increase of over $500 million versus a comparable outlook in which solar capacity received 50% ELCC.

The Company's interpretation of these results is that if solar resources receive less credit from MISO for the amount of installed capacity over time, customer costs will likely increase.

Q. Please discuss the final set of qualitative results of sensitivity modeling.

A. The final sensitivity discussed in this section is the evaluation of higher costs associated with transmission network upgrade costs. Additional information regarding network upgrade expense can be found in the direct testimony of Company witness Scott.

In the base case, a 2020 dollar value of $46 per kilowatt is included in modeling and added to the cost of all new resources selected to account for the cost of transmission expansion, to accommodate the added resource; however, as discussed by Company witness Scott, through collaborative discussions with Michigan Electric Transmission Company, LLC ("METC"), a sensitivity was performed using METC's projected network upgrade costs, a 2020 dollar value of $144 per kilowatt. This higher cost of transmission was added only to transmission-connected resources (not distribution-connected resources).

Primary observations of the analysis are that at $144 per kilowatt transmission network upgrade costs (verus $44 per kilowatt), under BAU assumptions of new resource *capital costs*, transmission-connected solar resources are still more economically favorable than higher-capital cost distribution connected solar. However, under a 35% capital cost reduction assumption on solar, as included in the EP and ET scenarios, the differential between transmission- and distribution-connected solar construction cost shrinks and the upward pressure on transmission-connected solar from the higher network upgrade costs results in selection of distribution-connected solar instead of transmission-connected solar.

The Company's interpretation of this analysis is that the price competitiveness between transmission- and distribution- connected solar is relatively narrow, and the "breakeven point," the price at which the overall economic comparison of the resources is equal, is somewhere within the ranges identified. Specifically, results indicated that if the cost of network upgrades – or any other related transmission costs – are higher than forecasted *and* capital costs of renewable assets are at least 35% lower than forecast – distribution-connected resources may be a lower-cost option than transmission-connected resources. The Company is agnostic to voltage level in its competitive solicitation process for solar capacity acquisition. Distribution-connected solar projects compete with transmission-connected solar projects in the same solicitation process; the customer benefits by the selection of the lowest-cost feasible projects, regardless of voltage level.

<u>New Technology Resource Selection Trends and Observations</u>

Q. Please explain how the new technology resource alternative selections are summarized.

A. As discussed in Section VIII of this direct testimony, Portfolio 3, the glide path portfolio, is the portfolio of greatest interest to the Company, as this represents a build plan that is feasible – the addition of incremental amounts of capacity slowly over time, an expansion that allows for the gradual growth of renewable and storage resources and customer programs. Therefore, the summary of Aurora-selected resource selections in Exhibit A-13 (STW-10) will correspond to Portfolio 3.

Exhibit A-13 (STW-10) presents five pages of the graphical results of Aurora's selection of resources across 116 sensitivities. Each page of the exhibit represents the amount of a single new technology resource alternative (in ZRC) chosen in a given year, across all scenarios and sensitivities included in this IRP. Page 1 presents the amount of solar capacity (in ZRC) selected in a given year in all sensitivities; page 2 presents the amount of battery storage ZRC; page 3 presents the amount of DR ZRC; page 4 presents the amount of wind ZRC; and page 5 presents the amount of natural gas ZRC. The dots shown on the graph represent the amount of solar capacity selected in a given year for a *single* sensitivity. The graph also includes a box and whisker format, which outlines the first and third quartiles within a shaded box, with the second quartile indicated with a horizontal line within the shaded box region; the maximum and minimum values with capped lines above and below the box ("whiskers"), and with outliers presented as single data points beyond the box and whisker collection of data points. The mean is indicated with an "x" data marker, also inside the shaded box region. Note that on pages 4 and 5, no shaded box region appears; this is because there were such few selections of wind and natural gas resources across the 116 sensitivities that the quartile values are 0.

Q. What is the purpose of summarizing the Aurora resource selections in graphical format, as presented in Exhibit A-13 (STW-10)?

A. By presenting the amounts of each new technology resource as a collection of data points, it allows one to observe Aurora's affinity for one type of resource or another, by year.

Given the significant number of sensitivities evaluated in this IRP, and more importantly, the varied assumptions of capital or program costs across the eight scenarios – the graphical representations included in Exhibit A-13 (STW-10) allows one to easily identify *trends* in resource selections. For example, it is immediately apparent that Aurora has a higher affinity for solar versus storage, when one compares the height of the box and whiskers presented on page 1 (solar resource selections) versus those presented on page 2 (storage resource selections). It is evident that solar is a more widely selected resource due to more favorable economics; furthermore, the density of data points in each year on page 1 indicates these amounts (shown on the y-axis) were selected in the *majority* of sensitivities, while the more sparse data points in each year on page 2 indicate that some sensitivities selected little or no storage. Similar observations as those made for storage can be drawn for the amounts of demand response, shown on page 3 – while material amounts of DR are selected across the multitude of sensitivities, the selection of DR is not as prolific as for solar. Pages 4 and 5 indicate that wind and natural gas resources were selected in very few sensitivities.

Q. What are the primary conclusions from the resource selections highlighted in Exhibit A-13 (STW-10) as it relates to the resources included in the Company's PCA?

A. The following observations and conclusions were drawn from the Aurora simulated selection of resources:

- EWR and CVR were "locked in," as previously discussed in this direct testimony and, therefore, not included in Exhibit A-13 (STW-10).
- Exhibit A-13 (STW-10) indicates Aurora's affinity for <u>solar</u> across all scenarios and sensitivities;

- When annual constraints on solar were hit (no more than 500 MW per year could be selected in a single year[13]), either demand response or storage were chosen, depending on the underlying assumptions of capital cost of storage or DR program costs.
  - For example, under BAU assumptions on storage and DR, the relatively lower program costs of DR, compared to base storage costs resulted in moderate levels of DR compared to storage. However, under EP assumptions, when solar costs are assumed at 35% below BAU levels, while DR was kept at base levels, storage was selected over DR. Finally, under ET assumptions, when both storage costs and DR costs are assumed to decline to levels 35% below BAU, the resources compete very closely.
- Only under specific assumptions in certain sensitivities were resources such as distribution-connected solar, wind, and natural gas selected.
  - Distribution-connected solar resources were selected in two types of sensitivities. The first is under AT capital cost assumptions for all resources. As discussed in Section IV, the AT scenario contemplated accelerated growth of distributed energy resources and assumed a 50% capital cost reduction on distribution-connected solar compared to BAU, while transmission-connected solar was assumed at levels 35% below BAU. In the AT scenario, distribution-connected solar was selected in lieu of transmission-connected solar.
  - The second sensitivity in which distribution-connected solar was widely chosen was in the sensitivity evaluating higher transmission network upgrade costs, as discussed in the above portion of this direct testimony, "NPV Economic Results".
  - Wind resources were only selected in few sensitivities with a 2024 capacity need, which corresponds to wind PTC levels at 60%.
  - New natural gas unit capacity was selected in the BAU CE scenario; while this resource technology may have provided the least-cost portfolio, the Company has decided not to include the construction of fossil-fueled resources in its IRP, as discussed in the testimony of Company witness Blumenstock. However, the BAU CE scenario indicates that natural gas resources provide customer value, as one of the first-selected resources, particularly for needs prior to 2026.
- Behind-the-meter-generation was included in sensitivity analysis, but not as a resource available for *selection.* Therefore, BTMG is not included in Exhibit

[13] Refer to the direct testimony of Company witness Battaglia for more information regarding this constraint.

A-13 (STW-10). Instead, BTMG was a "locked in" resource in specific sensitivities to understand which resources would be "kicked out" of selection. Generally, the customer-owned solar programs tend to reduce the amount of transmission- or distribution-connected solar resources, or battery storage resources.

New Technology Resource Selections in Retirement Base Case Optimal Plans

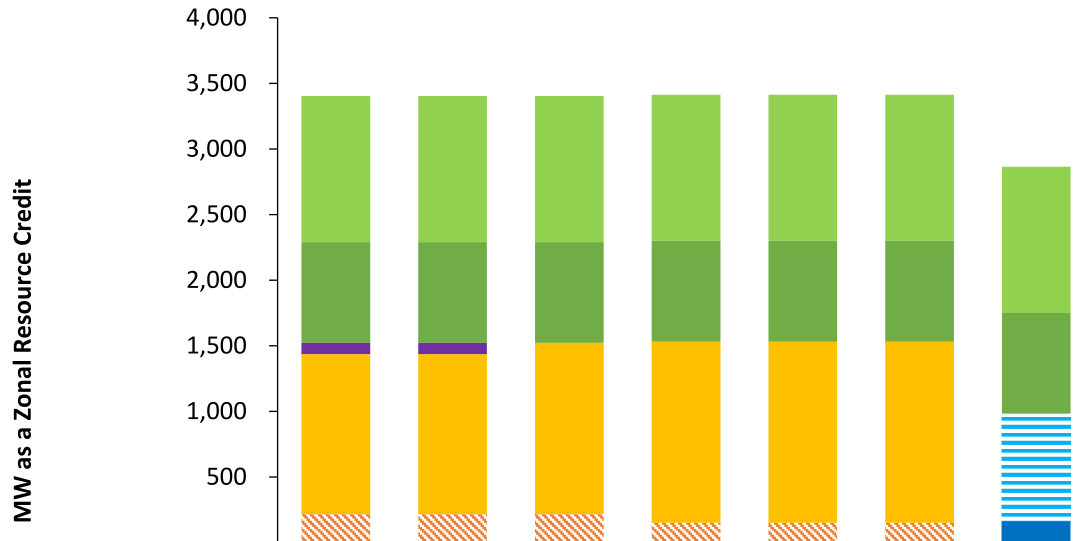
Q. The Company's PCA includes accelerated retirement of Campbell Units 1-3 and Karn Units 3&4 and the addition of two existing natural gas assets. Please discuss the Aurora optimal plan resource selections corresponding to that sensitivity in the applicable scenarios.

A. As discussed in Section VIII, the PCA, Portfolio 4, is a fixed resource plan. However, Portfolio 3, the optimal glide path portfolio was evaluated for the sensitivity considering retirement of the aforementioned resources. The specific build plan, Portfolio 3, corresponding to the accelerated retirement of Campbell Units 1 through 3 in 2025 and Karn Units 3 and 4 in 2023 and the addition of approximately 2,000 MW by 2025 of existing natural gas capacity under each scenario is presented in Exhibit A-14 (STW-11). This exhibit presents a graphical display of the resources selected as the optimal plan, with a summary table below the chart. The first eight pages of this exhibit shows the glide path optimal plan (Portfolio 3) for the retirement base case sensitivity under each of the eight scenarios; page 9 shows the same format of information for the final PCA, while page 10 shows the alternate plan.

Q. How were the results of the long-term capacity expansion runs, and the corresponding selection of resources by Aurora used to inform the decisions made regarding which resources to include in the PCA?

A. Development of the PCA required the selection of capacity resources to fill the needs remaining after the addition of the existing natural gas unit capacity, as supported in the testimony of Company witness Blumenstock. The addition of the gas capacity resolved capacity needs through 2030, following the accelerated retirement of Karn Units 3 and 4 and Campbell Units 1 through 3. The first significant shortfall of capacity would occur in planning year 2030, following the expiration of the MCV PPA. Figure 4, below, provides the graphical summary of Aurora-selected resources in year 2030 for the retirement base case sensitivities across all 7 scenarios (excluding the CO2 reduction scenario):

<u>Figure 4: Retirement Base Case Aurora-Selected Resources by 2030</u>



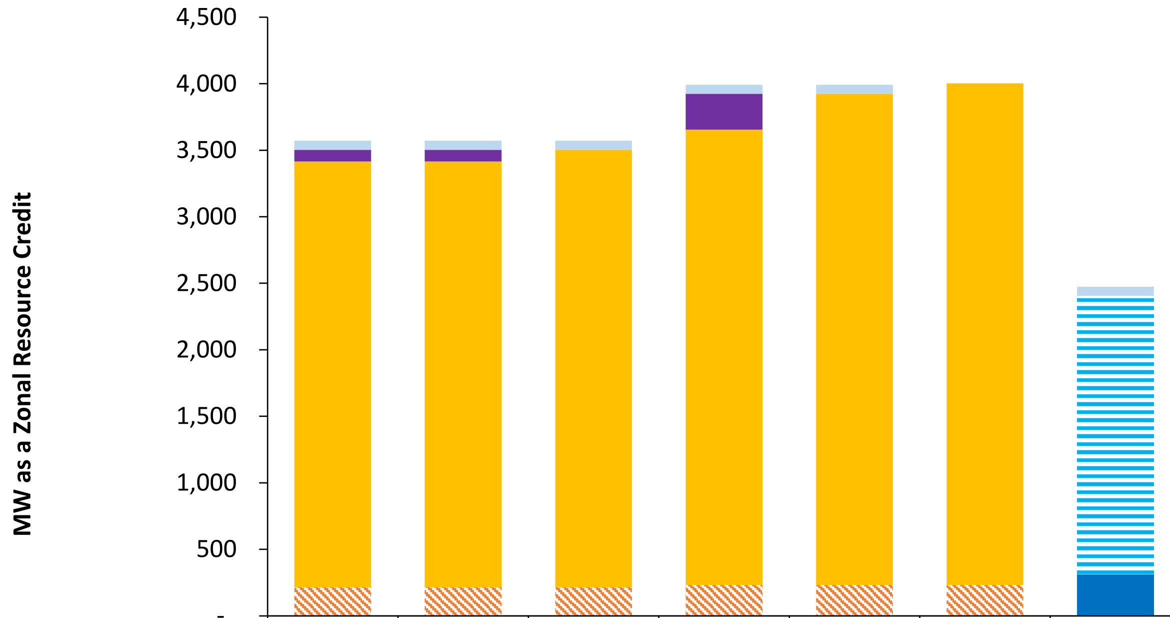
	BAUCE	ETCE	EPCE	BAUAEO	ETAEO	EPAEO	AdvTech
Covert Asset	1,114	1,114	1,114	1,114	1,114	1,114	1,114
DIG, Kalamazoo, Livingston	767	767	767	767	767	767	767
New Natural Gas	-	-	-	-	-	-	-
Battery Storage	-	-	-	-	-	-	-
Demand Response	87	87	-	-	-	-	-
Solar (Distribution)	-	-	-	-	-	-	820
Solar (Transmission)	1,219	1,219	1,306	1,382	1,382	1,382	-
Behind-the-meter generation	-	-	-	-	-	-	163
Energy Waste Reduction	216	216	216	150	150	150	-

In anticipation of ensuring capacity sufficiency by 2030, the following key conclusions were drawn, based on the Aurora-selected resource optimizations in the retirement base cases.

- The majority of remaining capacity need was filled by either transmission- or distribution-connected solar, approximately 2,500 additional MW (1,200 ZRC);
- As supported in Exhibit A-9 (STW-6), EWR was included in the portfolio, providing between 150 to 216 ZRC;
- At $85 per kW or less, the first two tranches of demand response were economically-selected in BAU CE and ET CE scenarios. Under MPSC assumptions, no DR was chosen; and
- Given the addition of baseload and dispatchable generation capacity, Aurora abstained from selections of battery storage capacity.

The next year of significant need in the portfolio that results in a step change of capacity shortfall is 2040. As discussed in the testimony of Company witness Blumenstock, the purchased gas units are assumed to cease operations by May 31, 2040. In Figure 5, the same graphical representation of the Aurora-selected resources is included for that year:

Figure 5: Retirement Base Case Aurora-Selected Resources by 2040



	BAUCE	ETCE	EPCE	BAUAEO	ETAEO	EPAEO	AdvTech
Covert Asset	-	-	-	-	-	-	-
CMS Assets	-	-	-	-	-	-	-
New Natural Gas	-	-	-	-	-	-	-
Battery Storage	68	68	68	68	68	-	68
Demand Response	87	87	-	269	-	-	-
Solar (Distribution)	-	-	-	-	-	-	2,095
Solar (Transmission)	3,203	3,203	3,290	3,425	3,693	3,772	-
Behind-the-meter generation	-	-	-	-	-	-	310
Energy Waste Reduction	213	213	213	231	231	231	-

The following key conclusions were drawn from Aurora optimization results by 2040:

- With the cease of operations of the purchased gas unit capacity, additional solar capacity is added, for a total of approximately 7,000 MW (3,500 ZRC) of incremental solar capacity;
- EWR programs continue year-over-year planned amounts, with between 213 and 231 ZRC contributing to filling the shortfall;
- In the first year following the cease of operation of the purchased gas units, storage capacity is added, albeit only about 70 MW; and
- Limited additional DR is selected, as compared with selections from 2030.

Given the pattern of observations in Aurora's resource affinities in the two years of greatest significant need (2030 and 2040), the PCA was developed under retirement base case assumptions and with the following additions of capacity:

- The first two tranches of DR will be included, totaling approximately 90 MW, given that these first two tranches were economically competitive under the Company's view of the most probable scenario, BAU CE, as a least-cost resource, by 2030;
- EWR and CVR programs will be included in the PCA, according to results of the potential study, as supported by economic favorability presented in Exhibit A-9 (STW-6);
- While not economically selected by Aurora, battery storage will be included in the PCA, though not until 2030, with the expectation that battery storage technologies will continue to advance, as they do today, resulting in improvements in economic favorability and operational flexibility, in the future;
- The remainder of capacity shortfall will be served by the gradual addition of solar capacity at no more than 500 MW per year, ensuring sufficiency of capacity to meet the PRMR in each of the targeted years 2030 and 2040. The Company does not dictate whether the solar capacity will be transmission or distribution-connected; instead, the competitive solicitation process ensures the lowest-cost resources are selected at either voltage level;
- The BTMG resource was evaluated to understand the portfolio changes associated with customer adoption of BTMG; but this resource was offered in at no cost, which obviously is not realistic. Due to uncertainty in adoption rates and resource costs, BTMG will not be included in the PCA at this time;
- As mentioned earlier in this direct testimony, the Company has no plans to install new-construction fossil-fueled generating capacity, and no CT capacity was selected, therefore those resources will not be included, either; and
- Wind was selected in so few sensitivities and not at all in the retirement base case sensitivities, so expansion of wind will not be included in this PCA.

Q. Were there any other ways in which Aurora results were used to inform the PCA?

A. Yes. While Aurora's capacity expansion and production cost modules were used to determine the resource selections from an *economic perspective*, Aurora was also utilized as a risk analysis tool, particularly, to perform an analysis to determine the extent to which the PCA and alternate plan would result in the potential for loss of load events. The next section of this testimony discusses this analysis in detail.

Q. The PCA not only meets the PRMR, but includes a significant amount of surplus in many years of the study period. Please explain why this is.

A. As explained above, the design of the PCA was primarily structured on filling large step-change losses of capacity in years 2030 and 2040 under the retirement base case assumption. As discussed in section VIII of this testimony, a glide path gradual addition of capacity was selected for the PCA, as it provides the Company with the flexibility to adjust as market and regulatory constructs change through time. It also allows the Company to pivot its plan, should more efficient or lower-cost resources become available. The gradual addition of capacity avoids large locked-in investments in a single technology resource. This method of capacity expansion, however, tends to "pre-build" for those targeted years (2030 and 2040), which will result in surplus capacity, particularly in years immediately proceeding the targeted years (for example, 2028, 2029, 2038 and 2039 will have the greatest amounts of surplus capacity).

Q. In the targeted years 2030 and 2040, a surplus of approximately 200 ZRC persists. Why does the glide path not solve for a 0 MW surplus in those years?

A. While the theoretical objective – and the solve target within Aurora optimizations – is to solve to meet the PRMR perfectly (i.e. result in a 0 MW shortfall or surplus), in practice, such a plan would pose significant risk. Many of the resources included in the Company's PCA rely on customer engagement – subscription to customer demand-side programs, or reliance on customer behavior to reduce their consumption. Additionally, as discussed in the testimony of Company witness Troyer, the Company's mechanism by which it secures solar capacity is done through annual competitive solicitations. The acquisition of capacity by these avenues carries risk – the risk to acquire an *exact* amount of ZRC, the risk to ensure the new capacity's commercial operation date aligns with MISO requirements to supply capacity by a given planning year, and the risk of developers' schedules and MISO's approvals adhering to the timeline presented in this IRP. Lastly, the PRMR, as well as the values of ZRC provided by portfolio resources are *forecasts,* which, as discussed in Section V of this direct testimony, carrying inherent risk.

These are significant execution risks customers would be exposed to if the Company's plan was to solve to exactly 0 ZRC. Instead, the PCA provides for a reduction to customer risks by planning for no less than 200 ZRC above projected PRMR levels.

<u>SECTION XI: CAPACITY SUFFICIENCY ANALYSIS</u>

Q. Company witness Blumenstock discusses the critical component of electric supply reliability within this IRP. Please discuss what your testimony will cover, with regard to the Company's capacity sufficiency analysis.

A. My testimony will cover the following details regarding the electric supply reliability capacity sufficiency analysis:

- Definition of the Company's capacity sufficiency analysis ("CSA") and how it compares and differs from a loss of load expectation analysis;
- A description of the scope and design of the Company's CSA;
- The evaluation parameters, or input variables, considered, or "shocked" as part of the CSA;
- A description of the particular sensitivities evaluated within the IRP scenario and sensitivities;
- The CSA modeling methodology and assumptions; and
- Results and interpretation of the CSA.

<u>Capacity Sufficiency Analysis and Loss of Load Expectation ("LOLE") Analysis</u>

Q. Can you define what is meant by Capacity Sufficiency Analysis and how it is like or differs from an LOLE analysis?

A. In this IRP, the Company has conducted a CSA to understand the sufficiency of a portfolio of resources to serve projected customer demand. A CSA is similar to an LOLE analysis in that both studies seek to evaluate how a given portfolio of resources performs under a set of simulations in which relevant input variables are exaggerated to understand the likelihood that the resource capacity may be insufficient to serve hourly demand. The studies may differ in a variety of ways. These differences include, but are not limited to: 1) an LOLE study is generally done at the regional transmission organization ("RTO") level, while the CSA was done for the Company's footprint only; 2) the metrics by which an LOLE determines sufficiency may be different than the metrics used by the Company in its CSA; and 3) an LOLE study generally will solve to a North American Electric Reliability Corporation ("NERC") defined target and determine an appropriate planning reserve margin by adding resources to ensure the standard is met, while the CSA identified results through its metric and used the metric to judge the sufficiency of portfolios – that is, additional resources were not added through the CSA analysis, nor is a reserve margin identified as part of the solution.

Q. Please provide a more detailed description of the Company's CSA, including the metric evaluated in the results of the analysis.

A. The goal of the CSA is to consider a pre-determined set of portfolio resources (supply or demand side) against a projected level of demand, identify the set of input variables that pose a risk to capacity sufficiency, and conduct a series of simulations that test the input variables, compared to base levels. By varying the input assumptions, the simulations create extreme conditions under which the portfolio's ability to serve hourly demands is tested. When enough of these simulations are run, one can reasonably assess the probability of capacity insufficiency in every hour of the year.

The metric developed for evaluation in the CSA is based on the ratio of the number of capacity insufficiency *events* divided by the total number of simulations. Within the context of the CSA, **capacity insufficiency** occurs whenever supply or demand-side resources are insufficient to meet demand in a given hour, which can be thought of as the loss of load in that hour. However, a capacity insufficiency **event** is defined as occurring whenever a loss of load hour either follows a non-loss of load hour – or is the first loss of load hour of the year. In this way, consecutive loss of load hours constitute a single loss of load – or capacity insufficiency – *event*. This differs from the standard LOLE metric, as defined in the NERC standard BAL-502-RF-03, which measures the sum of the probabilities for loss of load *for the integrated peak hour* for all days of each planning year analyzed, with no more than 0.1 as the target (0.1 day per year, or 1 day in 10 years).

<u>Evaluation Parameters</u>

Q. What evaluation parameters did the Company include in the CSA simulations?

A. Four evaluation parameters were evaluated within the CSA and are discussed in detail, below.

The first parameter evaluated focused on the availability of thermal generating units as well as Ludington pumped storage facility. Given a base assumption of planned (scheduled) maintenance and random outage rates, a frequency duration outage methodology is employed within Aurora to introduce more randomization – or the unpredictable nature of baseload or fast-responding generation resource availability. One hundred stochastic risk draws were simulated in Aurora, varying the duration and timing of unexpected generator outages. By randomly removing generator capacity from service, the simulations capture the risk that significant capacity resources may not be available when needed, potentially causing a loss of load hour. Information regarding the assumed random outage rate used as the baseline can be found in the direct testimony of Company witness Munie.

The second parameter evaluated is the risk of hourly customer demand changes. Load forecast uncertainty can be one of the greatest risks, with the potential for greatest variances. Company witness Munie discusses the standard deviation of plus and minus 9.1% included in the stochastic risk simulations that were used here, in the CSA, including the basis of the value to represent both weather and economic drivers of load variability. Given an initial seed, a series of risk factors are developed as the scalar multiple to hourly demands across the year, such that the standard deviation of the positive risk factors equals 9.1% and the standard deviation of the negative risk factors equals -9.1%. A risk factor, the scalar value multiplied to hourly demands, can be significantly higher than 9.1% or significantly lower than -9.1%, and the span of scalar multiples creates a range of load forecast simulations to which the specified portfolio can be compared.

The third parameter considered in the CSA is the unpredictability of intermittent resources, specifically, solar and wind generation profiles. As part of the 2018 IRP, the Company indicated plans to rely heavily on solar technology to meet its PRMR and serve hourly customer demands. Furthermore, under compliance with PA 295, Michigan's renewable portfolio standard ("RPS") requires achieving 15% renewable supply by 2021; correspondingly, the Company has added several wind generation resources to its portfolio. Given the significant portion of these intermittent resources within the portfolio, the CSA considers the risk of reliance on these resources as it impacts electric supply reliability. Specifically, the CSA considers a variety of hourly solar and wind generation profiles and randomly creates ten pairings of a solar profile and a wind profile, and then performs the stochastic risk simulations within each of the ten renewable profile pairings. This creates 1,000 iterations (ten renewable profile pairings evaluated under 100 stochastic risk draws) of risk analysis under the first three input variables considered.

The fourth evaluation parameter was the responsiveness of demand-side programs, specifically, demand response. Many optimization portfolios considered within the IRP have varying levels of reliance on DR to meet PRMR, which could result in a degree of risk for meeting peak demand levels – that is, the utility may not have direct control over customer responsiveness, and the greater the amounts of DR included to meet PRMR, the greater the risk of loss of load events. Accordingly, availability of DR was considered in the CSA. Specifically, the CSA evaluated impacts to loss of load potential at three levels: 1) customer interruption was limited to no more than forty hours per year (as consistent with the base case modeling); 2) customer interruption was limited to no more than ten hours per year; and 3) a final case, assuming customer response is very poor – evaluated as an extreme scenario assuming zero hours of demand response. Under each of 0, 10 and 40 hours of DR dispatch, each of the 1,000 risk simulations combined for a total of 3,000 CSA iterations.

<u>Sensitivity Description</u>

Q. Please provide a description of the IRP sensitivities evaluated within the CSA.

A. This testimony discusses two sensitivities evaluated within the CSA – the PCA and the alternate plan. Table 1 provides a summary of the installed capacity, in MW, of the portfolio of resources included in each of the PCA and alternate plan. This summary corresponds to 2032 installed capacity amounts, with further discussion on the selection of 2032 included below.

Table 1: 2032 Installed Capacity Included in CSA

Installed Capacity (MW)	PCA	Alternate Plan
Campbell 3 (CE Share)	0	785
Ludington Pumped Storage (CE Share)	1,170	1,170
Zeeland	853	853
Jackson	547	547
Hydroelectric	91	91
Wind	858	858
Other Renewable	69	69
Solar	4,810	5,414
Battery Storage	61	820
DR	698	840
Purchased Gas	2,153	0

Q. Why was year 2032 selected for the CSA?

A. The selection of 2032 is less an interest on a point in *time* and more an interest in studying a specific *portfolio* of resources. Most electric reliability studies, including LOLE conducted at the RTO level consider "interesting years," or years perhaps in which there is a significant change in the makeup of a portfolio or significant changes to demand, etc. In the case of the CSA, the Company defines an "interesting year" as a year following significant loss of baseload capacity, as well as considerable addition of intermittent resources. Year 2032 fits the bill well in both sensitivities evaluated. By 2032, in both the PCA and the Alternate Plan, Campbell Units 1 and 2 will be retired; Karn Units 1 through 4 will be retired; and the MCV PPA will have expired, removing over 3,000 MW of controllable generation capacity from the Company's portfolio. Additionally, approximately 5,000 MW of solar capacity is expected to be online by 2032 in both sensitivities, marking what certainly would be considered a significant amount of renewable (intermittent) capacity additions.

Q. What are the implications of choosing 2032 for the analyses instead of a year in closer proximity to current?

A. There aren't too many other factors at play in a CSA. This CSA is set up fairly simply, as discussed in greater detail below, as the direct comparison of capacity resources to demand, with little importance of changes to other variables (for example, uncertainty of energy or natural gas prices is not relevant in a CSA). Therefore, the only other variable of significance would be the demand forecast. As supported in the testimony of Company witness Breuring, the forecasted peak demand, as well as annual generation requirements are relatively flat; specifically, both peak demand and total generation requirements grow less than 2% higher than 2021 levels. It can be noted that application of a historically based standard deviation to a future year forecast more than ten years out generates levels of uncertainty that are not as easily managed as perhaps a more near-term evaluation could be. However, since the standard deviation is relatively broad, the Company expects the range of peak load and energy requirements will ensure the CSA is comprehensive in its stressing of demand variables. Given these considerations, the Company did not have great concern moving the CSA forward to 2032; in fact, the advantages to evaluating the dramatic changes to the portfolio far outweigh the loss of precision that may be expected from stepping the analysis so many years into the future.

Modeling Approach and Methodology

Q. What are the critical points of discussion regarding the modeling approach and methodology?

A. Items relevant to discussion regarding the modeling methodology include: 1) the number of iterations; 2) the model topology, including import capability; 3) the operation of battery and pumped storage within the simulations; and 4) the operation of DR within the simulations.

Q. How many iterations were simulated in the CSA and why was that number chosen?

A. Analyses such as the CSA or RTO-wide LOLE generally have a very high number of iterations – in the thousands or even ten thousand iterations. For example, in its 2019 IRP, DTE Company hired the Brattle Group to perform an LOLE study in which 10,000 iterations were simulated. For Consumers Energy's CSA, the design of the DR scenarios (3) and Renewable Profiles (10 pairings) meant there would be some multiplier to 30 sets of studies. The Company could have chosen 100, 200, 300 or any other number of stochastic simulations for Aurora to draw on the 30 scenarios; the selection of 100 draws was a choice to manage statistical validity with run time constraints. Running 3,000 iterations takes approximately a full week in the CSA Aurora model. Therefore, it seemed likely that anything more than a total of 3,000 iterations would be run-time prohibitive.

Q. How is the model topology set up and different from how Consumers Energy normally utilizes the Aurora model?

A. As discussed in Section V, for capacity expansion and production cost modeling runs conducted in this IRP, the Consumers Energy portfolio and demand are modeled within

Zone 7, and with the remainder of MISO modeled in detail, as presented in Exhibit A-8 (STW-5). However, to perform the 3,000 simulations, the model topology was revised to include only Consumers Energy's demand and its portfolio of supply and demand resources, with a single "unit" to represent energy import capacity, or the import capability Consumers Energy assumes in every hour of the study period. In this analysis, and consistent with the import capability assumed in the rest of this IRP, a value of 3,200 MW of import energy capacity was used. This capacity can be thought of as a "Capacity Import Limit ("CIL") *unit*," which was modeled as a resource within the Consumers Energy footprint. The maximum capability of the unit was 3,200 MW, available in every hour, and the price of the resource was assumed to be extremely high – higher than any other resource in the Consumers Energy portfolio[14] – such that the CIL unit would be the resource of last resort within the CSA simulations. The intention is that all Consumers Energy-owned and contracted resources would dispatch first and any remaining demand would be served by the CIL unit. If hourly demand exceeded the sum of the capacity of the CIL unit and all Consumers Energy portfolio resources, a loss of load hour occurs. Additional information regarding the CIL is included in the direct testimony of Company witness Scott and Company witness Thomas P. Clark.

Q. Is the CIL value of 3,200 MW the latest published value, from MISO?

A. No, Company witness Scott discusses that in its most-recently published LOLE report, MISO determined the new CIL as 4,888 MW.

[14] The price of the resource does not matter except to ensure dispatch order is maintained. There was no accounting of costs in the CSA, this is strictly a comparison of resource capacity to demand.

Q. What is a potential implication of the higher import capability?

A. Within the broader IRP, and as a general principle, a higher CIL would result in the potential for lower cost resources to be available to Zone 7. Within the context of the CSA, the higher CIL would generally result in the potential for lower loss of load event occurrence.

Q. Is the CIL unit's capacity of 3,200 MW shared by all entities on Zone 7?

A. In reality, yes, the CIL is shared amongst all entities within Zone 7. However, for purposes of the CSA, it was assumed that Consumers Energy has full access to the 3,200 MW amount in every hour of the study period.

Q. Is it a reasonable assumption that Consumers Energy would utilize all of the CIL?

A. Likely not, in practice. The Company considered pro-rating only a portion of the total CIL capacity to represent the amount Consumers Energy could import. However, in the end, the full 3,200 MW of capacity was assumed, for two primary reasons. First, there are tie-lines within Zone 7, for example, between Consumers Energy and DTE, that provide additional import capability to Consumers Energy, in addition to the CIL. Second, as stated, MISO has indicated a higher level of CIL than the values included in development of this IRP. The value of 3,200 MW should be thought of as a proxy for an estimate of power available to Consumers Energy customers outside of the Company's portfolio of resources.

Q. Please discuss operation of battery storage and pumped storage within the CSA.

A. The Aurora hourly commitment and dispatch of storage resource in the CSA simulations became complicated when the model topology was revised. Specifically, storage resources much charge – either from resources in the Company's portfolio, or from the "market," or the CIL unit, in this case. However, as was explained previously, the CIL unit was priced at extremely high levels, to ensure that Consumers Energy portfolio resources would dispatch before any reliance on outside sources. As a result, it was observed that with such a topology, the cost of charging storage resources became a constraint on the operation of those resources. To resolve this, "charging resources" were created within the CSA, priced at a typical energy price, derived from hourly runs with the model topology as presented in Exhibit A-8 (STW-5). By allowing the storage resources to charge at a price close to a locational marginal price ("LMP"), the economics of storage resources were not disturbed. Discharge of the storage units follows demand needs. With the additional charging resource capacity added (at the MW amounts of the battery and Ludington pumped storage recharge capacities), the system was off-balance and now in excess of supply (since the charging resources are only theoretical). To eliminate the excess supply, the CIL unit capacity is reduced by the total amount of charging resource capacity. For example, consider a battery storage unit with a 100 MW capacity (and corresponding 100 MW recharge capacity). A charging resource would be introduced into the CSA such that the storage unit could charge and discharge according to expected operations. However, this adds 100 MW of excess capability to the system; therefore, the CIL capacity is reduced, in this example, to 3,100 MW, to bring the equation back in balance.

Q. Please discuss dispatch of DR resources in the CSA.

A. DR resources in this IRP are modeled as load control resources, which generally are resources that respond to price, but can respond to adjust demand.

As discussed earlier in this section, the baseline outlook on DR assumes no more than forty hours of interruption per year, with additional scenarios evaluating ten hours or zero hours. Within Aurora, these limitations are handled via a logic that looks ahead, within the simulation, and identifies the highest demand hours of the year (either the 0, 10 or 40 highest demand hours) and schedules DR dispatch economically during those hours. It is noteworthy that even if a loss of load hour occurs, if that hour falls outside the 0, 10 or 40 highest hours of the year, demand response is not able to resolve the loss of load in these simulations.

CSA Results and Interpretation

Q. How are results of the CSA provided?

A. Results of the CSA are presented in three ways. First, a set of examples has been compiled, to show what a loss of load hour looks like, from an hourly supply and demand perspective. Second, a graphical representation of the concentration of loss of load hours per year is presented for both the PCA and the alternate plan. These are referred to as "heat maps," to identify the months and hours of the day that tend to have the most severe occurrence of loss of load. Third, presentation of results is given through the metric for measuring capacity sufficiency, discussed previously in this section. The total number of loss of load events per year is divided by the total number of simulations, such that an average number of loss of load events per year is determined across the 3,000 iterations.

Q. Please provide a detailed example of what a loss of load event "looks like" on an hourly basis, in terms of supply and demand balances.

A. Exhibit A-16 (STW-13) includes five pages, with illustrative instances of loss of load events. These examples do not necessarily correspond to either the PCA results or the alternate plan results; instead, they are simple examples of specific hours of loss of load events observed throughout development of the CSA. However, the portfolio of resources included in Exhibit A-16 (STW-13) correspond to a sensitivity that included high levels of renewable resources and storage resources, similar to the alternate plan.

Starting on page 1, a typical day is shown as a baseline: certain resources, such as solar, storage, Ludington pumped storage and DR, when applicable, are highlighted as column series; the rest of the resources are included in an aggregate, shown as "Remaining Resources." This aggregate would include many of the resources listed in Table 1, above. Two additional series are included in the column chart – "Import" which represents the CIL unit, described earlier in this section, and "Storage Charging," also discussed earlier, representing energy *consumed* to charge the battery or pumped storage resources. This series is colored similarly to the CIL unit because the charging capability is often provided by the CIL unit. Lastly, a line series is included, representing hourly demand. On this first page, conditions are as-expected, with demand sufficiently served in every hour of the day, which happens to be July 19, 2032.

On page 2, the same day is selected, July 19, 2032, however, this graphic corresponds to a stochastic risk iteration that increased load by a factor of 23%. Compared with the graph on page 1, it's clear that demand is higher, which causes resources to dispatch differently than they did on page 1. The exception is solar, which, in this example produced at exactly the same levels as the example from page 1. To meet the increased demand, many of the resources included in "Remaining Resources" are dispatched up, storage resources produce as much power as possible, given their current levels of stored energy, and Imports are elevated; however, in Hour 21, at 9:00 pm on a hot summer day, there is a loss of load hour – an insufficiency of resources to meet the persistently high demands.

Because the potential for loss of load occurs in any hour of the year – not just on hot summer days with high demand – an example was chosen, and shown on page 3, of the potential for loss of load during winter periods, particularly on cloudy days with elevated levels of demand. On page 3, demand on January 7, 2032, was increased by 17% in the stochastic risk simulation and solar outputs were essentially at zero MW in every hour of the day. Storage resources and Remaining Resources responded, Import utilization was maximized, yet hours 7-20 resulted in loss of load.

Page 4 includes two figures, which provide one of the most significant cases included in the exhibit. On page 4, two days are presented, September 7, 2032, and the day following, September 8, 2032. The significance of this set of examples is that this iteration, in which demand was increased by 23%, resulted in <u>consecutive</u> days resulting in loss of load. What's most interesting to notice is the operation of storage resources like batteries and Ludington. The storage resources begin responding to loss of load hours, occurring for the first time on September 7 in Hour 7, steadily increasing their output through Hour 11. However, by Hour 12, the resources are depleted of their storage contents and loss of load continues. In the following hour, the storage resources begin to *charge*, despite the on-going loss of load, when solar output increases and using some of the Import capability; later, the storage discharges in evening hours (starting in Hour 19 at 7:00 pm) when solar output declines. It can be observed that the mid-day charging periods exacerbate the loss of load event. The simulation chose to charge, despite the loss of load, because it identified periods of *more* severe loss of load hours later in the day as well as in the *next day*, shown in the second chart on this page. Similar observations can be made on September 8th – the model choosing to charge storage resources in Hours 1 through 6, despite on-going losses of load, with discharging occurring later in the day when the loss of load is at its deepest. This example illustrates that storage resources may not be the solution to resolve electric reliability concerns, especially on consecutive days of high demand. One of the challenges of these resources is the relatively short duration at which these resources can output capacity, and the relatively shallow depth of energy storage capacity. Further development of longform or long-duration storage resources may provide a solution some day in the future.

The last example, shown on page 5, addresses the role DR may play in reliability simulations. In this example, which occurs on August 4, 2032, with demand increased by 23%, the DR resource indeed responds during the highest demand hours – however, the loss of load event occurs when solar resources fall offline, in Hour 21 at 9:00 pm. While in practice, DR need not be dispatched only during the highest demand hours, this example illustrates the fact that DR programs may be limited in nature, and are unlikely to respond to resolve all loss of load hours.

Exhibit A-17 (STW-14) is a review of the same set of days provided in Exhibit A-16 (STW-13), but corresponding to a portfolio including the addition of controllable generation. As in the prior illustrative examples, the figures in this exhibit do not necessarily correspond to the PCA, but they were based on a portfolio of resources very similar to those presented in Table 1 under the heading “PCA”.

Page 1 of Exhibit A-17 (STW-14) again presents a baseline typical day, July 19, 2032. While similar to page 1 of the prior exhibit, it can be observed that with the addition of approximately 2,000 MW of baseload, reliable generation resources, referred to in the chart as “Purchased Gas,” resource capacity is actually in *excess* of demand in some hours.

The excess capacity in Hours 11 through 17 is available and used to charge storage resources like batteries or Ludington.

On page 2, the same day as the baseline example, but with load increased by a factor of 23% is again presented. In the high renewable portfolio example, a loss of load hour occurred in Hour 21, at 9:00 pm. In this exhibit, we see that the loss of load occurrence persists, which is not a surprise on a summer day with such signficant increases to demand; but the severity of the loss of load went from 603 MW of capacity insufficiency under the high renewable portfolio to 239 MW with the additional gas units added. As will be seen in the remaining examples, out of the five examples of loss of load hours highlighted in Exhibit A-16 (STW-13), only two of the five days discussed have loss of load occurrence under a portfolio that adds controllable baseload generating resources.

On page 3, compared with the loss of load occurring in winter months under the high renewable portfolio example, the controllable generation portfolio has resolved the loss of load hours. In Exhibit A-16 (STW-13), loss of load hours occurred between Hours 7 through 20; in Exhibit A-17 (STW-14), no loss of load hours are experienced, with the baseload generation resources maintaining sufficient supply throughout the day.

Page 4 is a comparison to the most concerning example presented in Exhibit A-16 (STW-13) – the persistence of loss of load hours on consecutive days of high demand, where a total of 44 hours of loss of load occurred over a 48-hour period. Under a portfolio including additional controllable generation resources, page 4 of Exhibit A-17 (STW-14) indicates that all 44 loss of load hours are resolved under the same demand conditions with the addition of 2,000 MW of baseload resources. This is a remarkable improvement in electric supply reliability.

Finally, page 5, the second of the five examples that still result in loss of load hours is presented. As before, even though DR responds during peak demand hours, as solar output declines, a loss of load hour occurs in Hour 21 at 9:00 pm, even with the additional baseload resources. However, as in the first example, while the high renewable portfolio experienced a loss of load of 574 MW on August 4, 2032, the controllable generation portfolio loss of load is only 210 MW.

Q. Please discuss the next presentation of CSA results – the graphical representation of all loss of load hour results.

A. These set of results can be thought of as "heat maps," indicating the concentration or severity of loss of load hours. Exhibit A-18 (STW-15) provides a visual that "locates" the specific hour of the day where loss of load events tend to occur. As this can vary by season, results are presented for each month of the year evaluated. Finally, shading is used to indicate how frequently a loss of load event occurs within each of the 24 hours. The darkest of the shading indicates an hour in a given month that resulted in the most number of loss of load hours, compared to the lightest of shading, which may correspond to only one loss of load hour across the 3,000 simulations. The shading is determined by taking the sum of all loss of load hours occurring within the simulations in the specified hour and month. For example, the darkest shade on page 1 corresponds to 679 total loss of load hours occurring in Hour 6 for all April months across the 3,000 iterations (8,760 hours per simulation).

Page 1 of Exhibit A-18 (STW-15) is the heat map corresponding to the CSA results for the alternate plan. In this high renewable portfolio of resources, we see the occurrence of loss of load hours in many hours of the day in the months of January, March, April, July, August, September, and December.

In contrast, on page 2, results of the CSA from the PCA portfolio of resources is presented, which reflect an obvious reduction in the occurrence of loss of load hours. In fact, only the months of July and November result in any loss of load, and the severity of loss of load is negligible, when compared with results from page 1. In this example, the darkest shading corresponds to Hour 8 in November, in which 18 loss of load hours occurred across all 3,000 simulations (8,760 hours per simulation).

These CSA heat maps demonstrate the compelling support that the PCA, which includes the addition of controllable generation, results in a dramatic improvement in the electric supply reliability concerns associated with high renewable portfolios. The PCA provides a balanced portfolio of controllable generation, pumped storage resources, renewable capacity, energy waste reduction, and demand response.

Q. Please discuss the third and final measure of results of the CSA, the metric discussed earlier in this section.

A. The final result of the CSA is a metric calculated as the total number of loss of load events per year divided by the total number of simulations. This result is presented as a figure directly on the heat maps provided in Exhibit A-18 (STW-15). On page 1, a red circle indicating the CSA result of 0.9 average loss of load events per year for the alternate plan. In comparison to similar analyses conducted by MISO, for example, this exceeds a comparable metric used in LOLE analysis by a factor of 9. Page 2 includes a green circle on the heat map, indicating acceptable levels of loss of load events, a result of 0.01 average loss of load events per year for the PCA.

Q. What conclusions can be drawn from the results of the CSA?

A. The CSA performed as part of this IRP is a robust review of the Company's long-term electric supply reliability sufficiency. Through vigorous statistical analysis, two portfolios have been evaluated and presented in this testimony. In addition to an existing portfolio of natural gas, pumped storage and other renewable sources of capacity, the first portfolio (the alternate plan) maintains a heavy reliance on renewable generation – particularly solar capacity – as well as the addition of DR and battery storage. The results of the electric supply reliability studies show that dependence on so many intermittent sources of generation results in significant periods of time for which the potential loss of load may occur. This conclusion is shown in the density of events presented in the heat map included on page 1 of Exhibit A-18 (STW-15). On the other hand, the second portfolio, the Company's PCA, includes a more balanced source of generation capacity – adding *controllable generation* to the proposed expansion of renewable energy and DR. The results of the study under this portfolio resulted in <u>significant</u> improvements in the long-term reliability sufficiency outlook, a remarkable reduction in the density of loss of load hours, highlighted on page 2 of Exhibit A-18 (STW-15).

<u>SECTION XII: CAPITAL, O&M, AND FUEL COST SUMMARY</u>

Q. What is the final topic you will discuss in your testimony?

A. The final set of data I will discuss and present is presented in support of the testimony sponsored by Company witness Jason R. Coker, for rate impact analysis.

Q. What are the capital and O&M costs associated with the PCA used in the rate impact analysis?

A. The capital and O&M costs associated with the PCA are summarized in Exhibit A-19 (STW-16).

Beginning on page 1, lines 1 through 9 of this exhibit, the cumulative installed capacity additions[15] associated with the Company's PCA are provided for each year 2021 through 2040. Lines 11 through 19 detail the capital expenditures associated with the *incremental* capacity resources added in each year. Lines 21 through 29 detail the cumulative O&M expenses associated with the resource additions.[16] Lines 31 through 35 provide the annual PSCR expenses at varying levels of capacity prices, and corresponding levels of capacity sales revenues associated with the PCA.

The same format of data is provided on page 2 for the Company's Alternate Plan.

Q. What are the capital and O&M costs associated with the required retirement analysis as part of the Settlement Agreement in MPSC Case No. U-20165, the 2018 IRP?

A. The capital and O&M costs supporting the required retirement analyses are summarized in Exhibit A-19 (STW-16) pages 3 through 15. These pages are structured similarly to pages 1 and 2 of this Exhibit, with the exception being lines 31 through 35 from pages 1 and 2. For the retirement sensitivities included on pages 3 through 16, the PSCR expense is provided only on line 31 and corresponds to the PSCR expenses assuming no capacity sales revenues – or in other words, assumes a capacity price corresponding to 0% of CONE. No rate impacts were conducted at varying capacity prices for these sensitivities.

[15] Capacity additions represent incremental MW to existing levels.
[16] As explained in Section VII of this direct testimony, for modeling purposes, all costs associated with incremental DR are assumed to be O&M-related; however, in reality, and presented in this exhibit, some of those costs will likely be allocated as capital investments.

Q. Are there any additional capital and O&M cost outlooks provided in this exhibit?

A. Yes. As discussed in the testimony of Company witness Blumenstock, the Company also considered the accelerated retirement of Karn Units 3&4 by May 31, 2025, instead of the base case assumption of May 31, 2031. This sensitivity is included on page 16 of Exhibit A-19 (STW-16) and follows the same format as pages 3 through 15 of this exhibit discussed above.

Q. What are the fuel cost projections provided in support of this IRP?

A. Projected coal, natural gas, and oil fossil fuel costs for existing owned generating assets, as well as the existing natural gas plants proposed for acquisition in the PCA, are provided in Exhibit A-20 (STW-17). For each of the eight scenarios discussed in Section IV of this direct testimony, a summary of the fuel costs projected has been provided, by scenario, and by portfolio, for each of the following portfolios: (i) Aurora selected (optimal plan); (ii) PCA; and (iii) alternate plan, where applicable. This exhibit contains 20 pages – three portfolios for each of the six Consumers Energy and MPSC scenarios (BAU, ET and EP, for a total of 18), as well as for the AT and Carbon Reduction scenarios. Pages 1 through 3 provide fuel costs associated with the BAU AEO gas scenarios – page 1 corresponds to fuel costs projected in the retirement base case Aurora selected portfolio, page 2 from the PCA, and page 3 from the alternate plan retirement assumptions. Pages 4 through 6 present fuel costs associated with each portfolio under BAU CE gas; pages 7 through 9 for ET AEO gas; pages 10 through 12 for ET CE gas; pages 13 through 15 for EP AEO gas; and pages 16 through 18 for EP CE gas; page 19 corresponds to the retirement base case optimal plan for AT; and page 20, the Carbon Reduction scenario results under retirement base case assumptions. On each page, lines 1 through 5 provide projected costs for coal, lines

6 through 9 and 13 through 27 provide projected costs for natural gas, and lines 10 and 11 provide projected costs for oil.

Q. Does this complete your direct testimony?

A. Yes.

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 Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))))	Case No. U-21090

DIRECT TESTIMONY

OF

ANNA K. MUNIE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

SECTION I: INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Anna K. Munie, 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 the Company?

A. I am a Sr. Engineering Technical Analyst in the Integrated Resource Planning Section of the Electric Grid Integration Department.

Q. Please describe your educational background.

A. I received a Bachelor of Science Degree in Animal Science in 2002 from Michigan State University and a Master of Business Administration Degree in 2016 from Michigan State University.

Q. Please describe your business and professional experience.

A. I joined the Company's Environmental Services Department in June of 2013. I was responsible for the implementation of the Company's Environmental Management System ("EMS") at different operational facilites on both the gas and electric side of the business. In October 2016, I began working in the Operations Performance area of Energy Supply Resources, where I managed key compliance, quality, and performance metrics associated with Company operations. I joined the Integrated Resource Planning ("IRP") team in December of 2017 as a member of the modeling team, and then expanded my role to include IRP implementation and strategy management in April 2020.

Q. What are your present responsibilities and duties as a Sr. Engineering Technical Analyst?

A. Presently I am responsible for the management of implementation activities related to the Settlement Agreement approved in Case No. U-20165, as well as strategy and project management activities related to the development and filing of additional IRPs. I also utilize Energy Exemplar's Aurora software platform to perform risk assessment and stochastic risk modeling for the purposes of long-term electric supply planning.

SECTION II: PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. My direct testimony will explain the Risk Assessment Methodology used by the Company in the development of the IRP.

My direct testimony will provide quantitative support that the Proposed Court of Action ("PCA"), discussed in the direct testimony of Company witness Richard T. Blumenstock, was subjected to a thorough risk assessment evaluation, including stochastic risk analysis as required as part of the Settlement Agreement of Case No. U-20165, the 2018 IRP, and the modeling of all optimized portfolios in all scenarios as required by the same Settlement Agreement.

My direct testimony will provide quantitative support that this same rigorous risk assessment process was applied to evaluation of the optimal portfolios selected by the Aurora software model, as well as the Company's Alternate Plan.

I will describe the process that was used to develop the risk variables evaluated in this IRP, including which variables were evaluated, the range of risk assigned to each variable, and the methods used to conduct risk analysis modeling.

My direct testimony will describe the risk assessment modeling process that was performed, and the results from that modeling.

My direct testimony will provide support of the Company's PCA as the most reasonable and prudent plan, and demonstrate that the PCA withstands a robust risk analysis and evaluation that is consistent with the Company's risk assessment methodology.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibit, which was prepared by me or under my supervision:

Exhibit A-21 (AKM-1) 2021 IRP Risk Assessment Results By Risk Variable.

Q. How is the remainder of your direct testimony organized?

A. The remainder of my direct testimony is organized in sections as follows:

SECTION III: RISK ASSESSMENT METHODOLOGY

SECTION IV: RISK ASSESSMENT MODELING

SECTION V: RISK ASSESSMENT VARIABLES

SECTION VI: RISK ASSESSMENT RESULTS

SECTION VII: RISK ASSESSMENT CONCLUSIONS

SECTION III: RISK ASSESSMENT METHODOLOGY

Q. Why is a risk assessment conducted in an IRP?

A. Performing a risk assessment allows the Company to see how a group of resources may perform under a variety of uncertain futures. By fluctuating certain leading indicators such as demand, performance of thermal and renewable assets, fuel prices, and other variables, the Company can evaluate how the PCA, Alternate, or Optimal plans will respond to potential changes in future conditions impacting customer costs, electric supply reliability, and the environment. Applying a robust risk assessment methodology and performing risk analysis using multiple methods helps the Company evaluate how changes in key variables may impact base forecasts and assumptions, and how changes to those forecasts or assumptions may impact customer costs, electric supply reliability, plan resiliency to typical and extreme events, and the planet.

Q. What are the filing requirements for risk assessment in an IRP?

A. The Commission's IRP Filing Requirements adopted in Case No. U-18461, under "Risk Assessment Methodology" (page 4), states:

> The utility's IRP filing shall include a thorough risk analysis of the preferred plan and the optimal plans for each of the scenarios specified in the Michigan Integrated Resource Planning Parametmers (MIRPP), as well as all additional scenarios and sensitivities filed with the IRP application. The plans should be feasible and differ in generation mix from the preferred plan and MIRPP plans. The intent of the risk assessment includes a discussion of the methodology used for risk analysis including the utility's justification for the chosen methodology over other alternatives. Acceptable forms of risk analysis include, but are not limited to, the following: scenario analysis, global sensitivity analysis, stochastic optimization, generating near-optimal solutions, agent based stochastic optimization, mean-variance portfolio analysis, and Monte Carlo simulation.

Q. Please explain how the Company is meeting the filing requirements for risk assessment in this IRP.

A. The Company utilized scenario and sensitivity analysis, stochastic risk analysis, deterministic risk analysis, which is a form of sensitivity analysis, and optimal portfolio evaluation in conducting the risk assessment for this IRP.

Q. Please describe which portfolios were evaluated in the risk assessment.

A. The PCA, Alternate Plan, and Optimal portfolios for each scenario as described by Company witness Sara T. Walz were all evaluated under the Company's risk assessment methodology. These scenarios are Consumers Energy's Business As Usual ("BAU"), Emerging Technologies ("ET"), Environmental Policy ("EP"), and Advanced Technologies ("AT") referenced as BAU CE, ET CE, EP CE, and AT, respectively, and the Michigan Public Service Commission's ("MPSC" or the "Commission") BAU, ET, and EP scenarios referenced as BAU AEO[1], ET AEO, and EP AEO, respectively. The PCA and Alternate Plan were evaluated under the BAU CE scenario.

Q. Please explain in more detail the Risk Assessment Methodology used by the Company in the development of the IRP.

A. The Company used a robust, iterative, five-step process to assess the levels of risk related to selecting a resource portfolio. These steps consist of:

1. **Portfolio Optimization Reviews** – The portfolio optimization reviews are used to identify resource tradeoffs and/or tipping points for the selection of different supply or demand side resources. For example, under a certain set of resource assumptions the Aurora model may select a combustion turbine as the most economic resource selection. Under another scenario or sensitivity with different assumptions, the model may instead select a solar resource as the most economic choice. The different assumptions identified within the

[1] "AEO" scenario designation applied to those scenarios which utilized the U.S. Energy Information Administration ("EIA") 2020 Annual Energy Outlook ("AEO") natural gas price forecast for modeling purposes.

scenarios and sensitivities modeled in the IRP help to guide the development of the PCA through the evaluation of when certain resources are selected or what assumptions must be true to identify the tipping points between one type of resource over another. Exhibit A-XX (STW-1) and Exhibit A-XX (STW-2) provide descriptions of the modeled scenarios and sensitivities; the evaluation of the resource portfolios generated from modeling formed the basis of the risk assessment in order to understand where trade-offs were occurring between different scenarios and sensitivities;

2. **Net Present Value ("NPV") Review of Portfolio Optimizations –** NPVs help to understand the level of costs or savings that customers incur with a particular resource portfolio. By comparing the NPVs of portfolio optimizations generated under each scenario and sensitivity, insights into whether customers realize increased costs, savings, or remain cost neutral is determined. NPV comparisons are made with the portfolio optimizations under each scenario and sensitivity run. This same approach is used when comparing the PCA and Alternate plan in each developed scenario. The lowest NPV plan represents the least-cost plan for customers. Exhibit A-12 (STW-9) provides all of the NPVs resulting from the modeled scenarios and sensitivities;

3. **Evaluation of all Optimized Portfolios in All Scenarios –** The above steps are important components of the risk assessment methodology because they inform the development of the final PCA and identify the cost, savings, or cost neutrality that would be incurred with each optimal resource portfolio. After these initial steps are performed, an additional step is taken to evaluate all optimized portfolios in all scenarios, to further evaluate how a group of resources performs under a different set of assumptions. As an illustrative example, the resources selected under the BAU CE scenario were then locked in and modeled under the ET CE and EP CE scenarios, and the differences in NPVs were compared. This allowed the Company to see how the resource selections identified as optimal under an identified set of assumptions performed when modeled under a different set of assumptions. Exhibit A-11 (STW-8) provides a table identifying which optimized portfolios were modeled under which scenarios. Exhibit A-12 (STW-9) provides the NPVs resulting from this evaluation.

   This same methodology was applied to the PCA, which was also run through all CE and MPSC scenarios to show how the PCA performed under assumptions associated with the different scenarios. Exhibit A-12 (STW-9) provides the NPVs resulting from this evaluation;

4. **Stochastic Risk Analysis** - In addition to the evaluation of optimized portfolios under different scenario assumptions, and the evaluation of NPVs resulting from different scenarios and sensitivities, it is important to understand the impact that one or multiple input variables can have on system characteristics, such as cost. Stochastic risk analysis is one method that can

be utilized to understand the impact an identified variable has on a pre-determined set of portfolio resources, by using probabilistic distribution to randomly fluctuate the identified variable(s) within an established standard deviation from the base value. The Optimal portfolios for each identified scenario, the PCA under the BAU CE scenario, and the Alternate Plan under the BAU CE scenario were all evaluated utilizing a stochastic risk assessment for the following variables: electric demand, solar and wind availability, and thermal generator availability; and

5. **Deterministic Risk Analysis –** Deterministic risk analysis is a form of sensitivity analysis that can be utilized to understand the impact of one or more variables on a pre-determined set of portfolio resources. Deterministic risk analysis involves defining a specific set of potential futures for an identified variable and evaluating a resource plan against each of those identified futures, then using that information to evaluate impacts to system characteristics. The Optimal portfolios for each identified scenario, the PCA under the BAU CE scenario, and the Alternate Plan under the BAU CE scenario were all evaluated utilizing a deterministic risk assessment for the following variables: natural gas prices, carbon prices, and demand response ("DR") availability.

SECTION IV: RISK ASSESSMENT MODELING

Q. Please describe the software used to conduct risk analysis in this IRP.

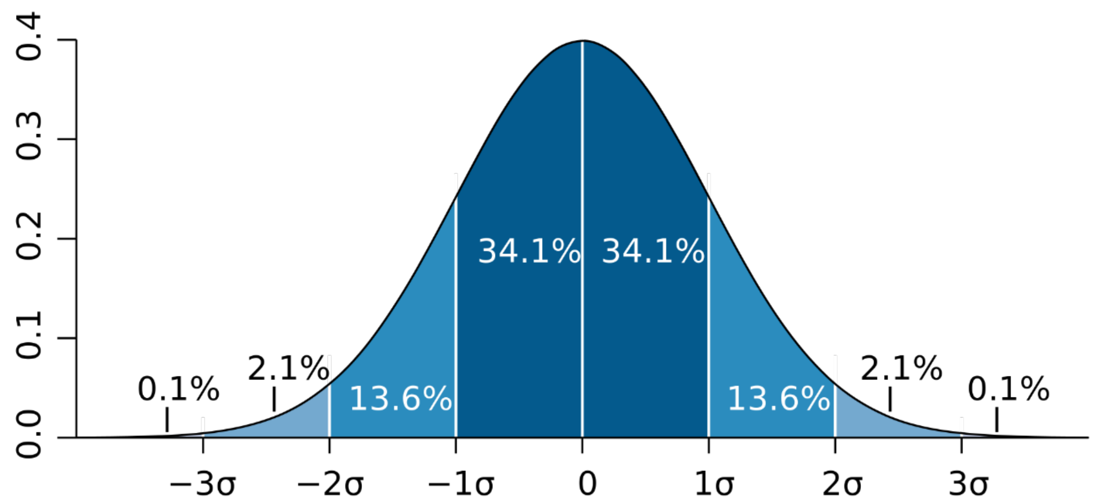
A. The stochastic risk analysis was executed using the Aurora modeling software. Aurora, a computer software application developed by Energy Exemplar, supports electric utility decision analysis and corporate strategic planning. Company witness Walz provides additional information on the Aurora model and how it was utilized in the development of the Optimal portfolios, PCA, and Alternate Plan. For the purposes of risk analysis, the Aurora software model offers the capability to perform Monte Carlo simulations. Monte Carlo simulation is a statistical risk analysis method which involves running a large number of modeling iterations while randomizing the fluctuations in one or more identified variables, in order to simulate uncertainty in forecasting or future industry conditions. By using probability distribution in a Monte Carlo simulation, different probabilities can be assigned to different outcomes, so that the outcome of the simulaton is a distribution of all possible outcome values based on the probabilities assigned to them. This allows for more realistic results of the simulation as the most extreme fluctuations in a risk variable are assigned the lowest probability of occurence. Aurora's methods for conducting risk assessment were used in this IRP as it was not feasible or pratical to pursue a completely separate risk analysis tool when stochastic risk analysis capabilities were available using the same software application that was utilized in the development of all resource portfolios.

Q. Please describe how Aurora performs stochastic risk analysis using Monte Carlo simulation.

A. The risk analysis functionality of the Aurora modeling software allows the user to identify individual or multiple input variables that can be evaluated for defined levels of volatility or uncertainty. The input variable to be evaluated is initially assigned a standard deviation from its base value, applied as a percentage. Using an initial risk seed, the Aurora model then applies a series of risk factors as a scalar multipler to the identified risk variable, such that the standard deviaton of the positive risk factors equals the percentage entered as the standard deviation in the model, and the standard deviation of the negative risk factors equals the percentage entered as the standard deviation in the model. As it is the calculated risk factor that is applied to the variable being evaluated when the Monte Carlo simulation is conducted, the risk factors assigned to the variable over the course of the study can be significantly higher or lower than the initial percentage value entered as a standard deviation.

The Company used a normal probability distribution for all Monte Carlo simulations in the stochastic risk analysis. A normal, or "bell-curve" distribution means that the values in the middle of the bell curve have the highest probability of occurring, and the values at the tail ends of each side of the bell curve have the lowest probability of occurring. In total, 68% of the data results from a simulation will fall within one standard deviation of the variable's base value, 95% of the data results will fall within two standard deviations of the variable's base value, and over 99% of the data results will fall within three standard deviations of the variable's base value, as seen in Figure 1 below.

<u>Figure 1: Example of a Normal Probability Distribution</u>



In order to generate a normal distribution curve of potential outcomes, the Monte Carlo simulation needs to calculate results over a large number of modeling runs, or iterations. Each iteration of the Monte Carlo simulation repeats the same defined parameters of the initial modeling run over and over again, each time randomly fluctuating the identified risk variable by a different amount. As the outcome of each iteration is generated, it forms a data point within the defined probability distribution for the Monte Carlo simulation.

Q. What planning period was used in the stochastic risk analysis?

A. The planning period used for the stochastic risk analysis was the same as that used for the optimization process, a 21-year period beginning January 1, 2020 and ending December 31, 2040.

Q. How many iterations were run in the stochastic risk analysis?

A. Each Monte Carlo simulaton performed as part of the stochastic risk analysis study included 100 iterations, meaning that in each simulation the identified risk variable was fluctuated within the defined probability distribution 100 times.

Q. Please describe how Aurora performs deterministic risk analysis.

A. Deterministic risk analysis was modeled in the same way sensitivity analyses were conducted as part of the IRP modeling process. For more information on the modeling of sensitivity analyses within the IRP, please see the testimony of Company witness Walz. To conduct deterministic risk analysis using the Aurora software, a set of modeling runs was conducted by either explicitly fluctuating the identified risk variable against selected percentage variations in forecasted amounts (i.e. natural gas prices), applying selected potential forecasts of the identified risk variable to a fixed portfolio of resources (i.e. carbon pricing), or modifying the responsiveness of the identified risk variable by certain levels (i.e. DR availability). Using the results of multiple sensitivity runs, a range of results could then be evaluated to determine the overall effects of these risk variables on the identified resource portfolios.

SECTION V: RISK ASSESSMENT VARIABLES MODELED

Q. Please describe which variables were evaluated as part of the stochastic risk analysis in this IRP.

A. The variables evaluated in the IRP using stochastic risk analysis were electric demand, solar and wind resource availability, and thermal generator availability.

Electric demand was chosen as a risk variable for several reasons. First, continued interest in electrification in other industries such as the transportation and building industries creates the possibility for significant future load growth. Performing a risk assessment that includes electric demand as a risk variable allows the Company to see how increases in electric demand would affect customer costs as well as whether there were any impacts on the reliability of a resource portfolio. The second reason to evaluate electric demand as a risk variable is that while electric demand reductions from COVID-19 were temporary, evaluating potential futures that include a decrease in electric demand allow the Company to see the cost impacts to a fixed portfolio of resources if electric demand were to decrease over the study period, and whether that poses a risk to the Company.

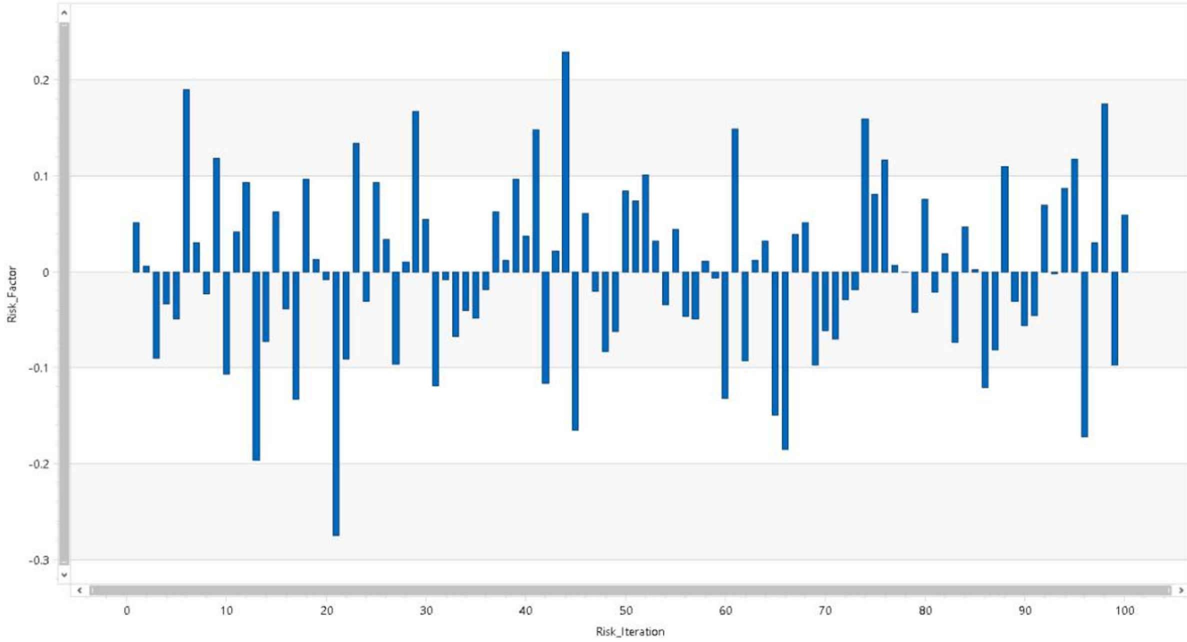
The availability of solar and wind resources was chosen as a risk variable due to the intermittent nature of their production and their dependence on weather conditions. These resources form a significant portion of the Company's current Clean Energy Plan as well as the current PCA, and are a key contributor towards the Company's Net Zero Carbon Emissions goal. By evaluating the availability of these resources using stochastic risk analysis, the Company could evaluate a wide range of weather and outage conditions that may affect the performance of these resources over the IRP study period, and evaluate both the cost impacts that result from differences in expected availability and production, as well as evaluate how resources are dispatched under different renewable resource availability conditions.

Thermal generator availability was chosen as a risk variable in order to evaluate the impacts seen if one or more thermal generators (i.e. coal-fired or gas-fired) suffers from a higher outage rate than anticipated, through either unexpected maintenance, extreme weather conditions, or a disruption in fuel supply. A decrease in the availability and dispatch of large baseload generating units could result in impacts to the reliability and resiliency of a resource portfolio; including thermal generator availability as a risk variable allows the Company to evaluate if a portfolio is diverse enough to stand up to unexpected outages or other conditions that have the potential to affect baseload thermal resources.

Q. Please describe the range of electric demand that was evaluated in the stochastic risk analysis.

A. Using a base standard deviation of +/- 9.1% and the assigned risk factors from the risk study, the range of electric demand evaluated for each of the identified resource portfolios was -27% to +23% from the Company’s base demand forecast. A visual respresentation of the range of risk factors assigned during the electric demand stochastic risk analysis can be found below in Figure 2.

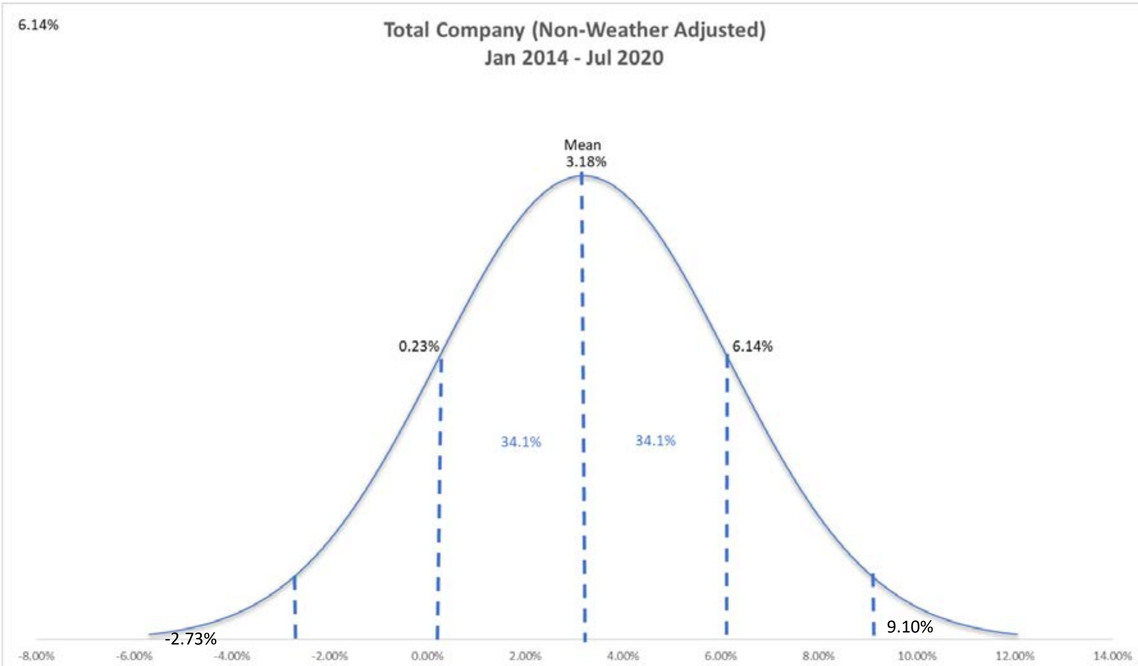
Figure 2 – Range of Risk Factors, Stochastic Risk Analysis – Electric Demand



Q. How was the range of electric demand to evaluate in the stochastic risk analysis determined?

A. The range at which to fluctuate electric demand was determined by reviewing the accuracy of total company (non-weather adjusted) actual to projected electric demand forecasts from January of 2014 to July of 2020 (see Figure 3 below). The most extreme monthly deviation from the planned forecast for electric demand over this time period was 9.10%, therefore it was determined that this value should be used as the base standard deviation utilized in stochastic risk analysis to ensure that the risk analysis was robust and had the ability to test extreme scenarios for electric demand. While values such as 23% lower demand or 27% higher demand over the study period are unlikely, including this range of volatility in risk analysis allows the Company to better evaluate uncertainty and begin to understand the conditions of a future world with high variability in the levels of demand seen, such as a potential future world with high levels of electrification.

Figure 3: Company Non-Weather Adjusted, Forecast Accuracy Jan 2014 – Jul 2020



Q. What Midcontinent Independent System Operator, Inc. ("MISO") Local Resource Zones ("LRZs") were evaluated for electric demand in the stochastic risk analysis?

A. All MISO LRZ were evaluated for fluctuations in electric demand. A 100% correlation was established between each LRZ in the stochastic risk analysis, to ensure that for each risk iteration the risk factor assigned to each LRZ was the same. This allowed the Company to better evaluate the impact of an overall increase or decrease in demand by having each LRZ fluctuate up or down by the same level.

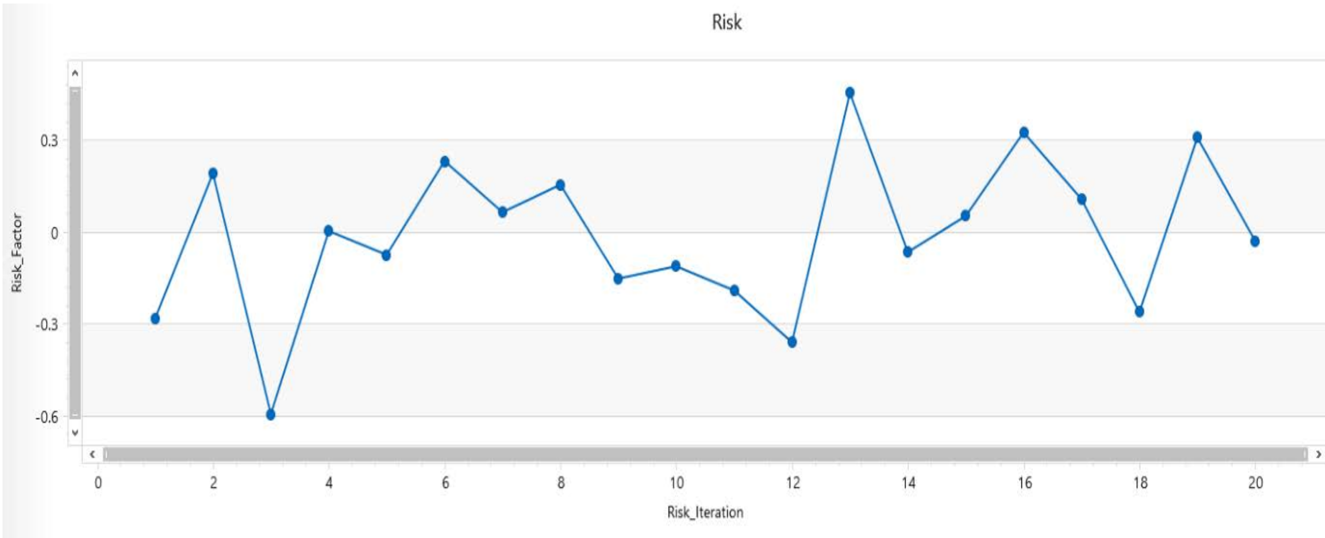
Q. How was solar and wind resource availability evaluated in the stochastic risk analysis?

A. The availability of solar and wind resources was selected as a risk variable in the stochastic risk analysis due to the intermittency and weather dependency associated with these resources. Therefore, the availability of solar and wind resources was evaluated in the stochastic risk analysis by randomly fluctuating the defined hourly forced outage profile of each solar and wind resource in the Company's portfolio. This simulates fluctuations in the availability of these intermittent resources as weather conditions vary over the course of the study period, as well as simulates the potential for these resources to have unexpected outages or performance issues.

Q. Please describe the range of solar and wind resource availability that was evaluated in the stochastic risk analysis.

A. Using a base standard deviation of +/- 25% and the assigned risk factors from the risk study, the range of fluctuation in availability that could be evaluated for each solar or wind resource was -77% to +88% of that resource's assigned forced outage rate. While the individual risk factor that could be assigned to each resource was extreme, a 0% correlation was assigned for each solar and wind availability risk simulation, to ensure that not all resources were assigned an extreme value during the same risk iteration. This resulted in a more widely distributed overall fluctuation in availability for all resources in each iteration, which is more representative of varying availability due to weather volatility. An example representation of a range of risk factors that can be assigned to an identified resource during just a portion of the iterations conducted when evaluating wind and solar availability is shown in Figure 4.

<u>Figure 4 – Example Range of Risk Factors, Stochastic Risk Analysis-Solar/Wind Availability</u>



Q. What was the source used to determine the range of solar and wind resource availability?

A. The range at which to fluctuate the availability of wind and solar resources was determined by reviewing historical performance of Company-owned solar and wind resources. Company Solar Gardens production history (Grand Valley State University, Western Michigan University, and Circuit West) was evaluated from 2016-2019, and Company wind farm production history (Lake Winds, CrossWinds I and II) was evaluated from 2013-2018. The most extreme deviation from expected performance identified for each type of resource, +/-25%, was used to set the standard deviation for the availability of these types of resources in the stochastic risk analysis.

Q. Which solar and wind resources were evaluated for availability in the stochastic risk analysis?

A. All existing Company-owned wind and solar units, all existing wind and solar units under a power purchase agreement ("PPA") with the Company, as well as all selected solar and wind resources levels for the Optimal plans, the PCA, and Alternate Plan were evaluated at varying levels of availability. As mentioned previously, no correlation was established between the hourly forced outage profile for these resources, in order to simulate different weather or outage conditions in different parts of the state during the study period.

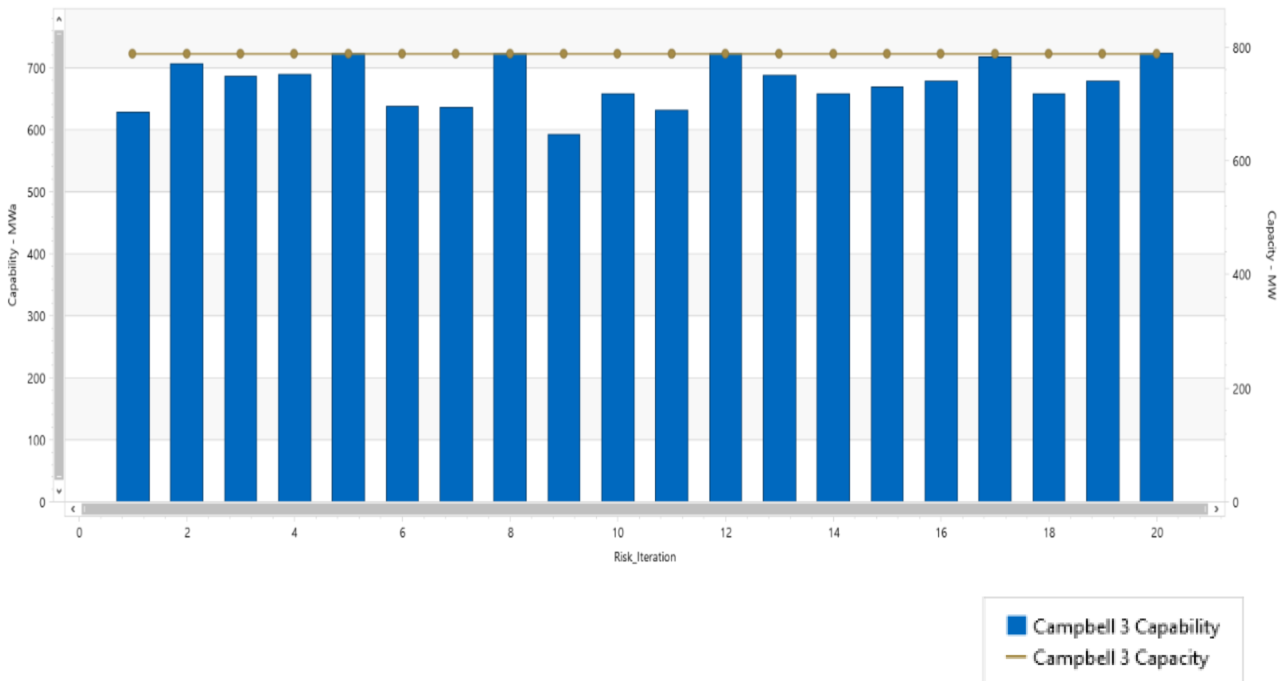
Q. How was thermal generator availability evaluated in the stochastic risk analysis?

A. Thermal generator availability was evaluated by randomly modifying the assigned outage rates of Company-owned baseload or fast-responding thermal generating units. This represents the potential for unexpected or unscheduled outages of these types of resources during the study period. Modification of assigned outage rates for each risk iteration was performed using the Frequency Duration method in Aurora. Frequency Duration is an outage method that can be assigned during risk analysis to simulate an unexpected or unforeseen outage of thermal resources. This option allows for identified units to fail, or fail to return to service, at any time during a Monte Carlo simulation, given a base assumption of planned maintenance schedules and defined outage rates. A Mean Repair Time is also entered in Aurora to restrict how quickly the thermal generator can come back online after it is assigned an unexpected outage.

Q. Please describe the range of thermal generator availability that was evaluated in the stochastic risk analysis.

A. A specific range of outage rates is not defined for the stochastic risk analysis modeling of thermal generator availability. Instead, the Frequency Duration outage methodology introduces outage randomization for thermal generating units to either fail, or fail to return to service, at any time during each iteration of a risk simulation, which then affects the overall capability of that unit for each year of the study. As an example, Figure 5 shows the capability fluctuations, when compared to base capacity, for J.H. Campbell ("Campbell") Unit 3 in the year 2023, for just a portion of the iterations performed in a stochastic risk analysis study.

Figure 5 – Example Range, Example Year, Example Resource of Thermal Generator Capability Flucuations, Stochastic Risk Analysis



Q. What was the source used to determine the range of thermal generator availability?

A. The baselines for thermal generator availability were the planned maintenance schedules and defined outages rates for thermal generating units included in the Aurora model. For each thermal generating resource, a planned maintenance schedule is entered to reflect scheduled maintenance and outage activites planned to support operation of those units. In addition, each thermal generating unit is assigned an outage rate designed to simulate the expected percentage of time, in each year of the study, that the unit may go offline unexpectedly due to unexpected maintenance, extreme weather conditions, or a disruption in fuel supply.

Q. What resources were evaluated for thermal generator availability in the stochastic risk analysis?

A. All current Company-owned thermal generating units were evaluated for all years of the study period. This includes Campbell Units 1, 2, and 3; D.E. Karn ("Karn") Units 1 through 4; Zeeland Generating Station; and Jackson Generating Station. In addition, the New Covert Generating Facility, Dearborn Industrial Generation, Livingston and Kalamazoo Stations were also included in the evaluation of thermal generator availability once ownership transferred to the Company in planning years 2023 and 2025, respectively. The baseline assumed outage rates and associated mean repair time used as a baseline for the availability of these thermal generating units are included below in Table 1.

Table 1: Thermal Generating Units Random Outage Rates and Mean Repair Time

Unit	Average Outage Rate While Active in Study Period	Mean Repair Time (Hrs)
Campbell 1	17.5%	174.50
Campbell 2	35.5%	230.01
Campbell 3	5.6%	126.51
Karn 1	39.5%	199.49
Karn 2	33.0%	140.89
Karn 3	33.0%	78.38
Karn 4	16.8%	70.69
Zeeland 1A	4.2%	34
Zeeland 1B	4.2%	29.70
Zeeland CC	4.2%	44.97
Jackson	4.4%	6.58
Covert	1.3%	6.58
DIG	0.9%	6.58
Kalamazoo	7.5%	6.58
Livingston	6.0%	6.58

Q. Please explain which variables were evaluated as part of the deterministic risk analysis in this IRP.

A. The variables evaluated in the IRP using deterministic risk analysis were natural gas price, carbon price, and demand response availability.

The price of natural gas is a key indicator of fluctuations in energy prices. Therefore, evaluating natural gas as a risk variable gives the Company essential information regarding how varying resource portfolios would perform, not just under different natural gas price levels, but how those portfolios would perform as energy prices move up or down. The sensitivity of a portfolio to the price of natural gas indicates how sensitive that portfolio will be to fluctuations in energy prices, which is a key driver of the customer affordability of that portfolio. Natural gas price is such a key indicator of a portfolio's potential risk that this type of sensitivity analysis is used as a key input in the NPV review of portfolio optimizations. Company witness Walz discusses how the NPV of a portfolio is calculated in more detail.

Carbon pricing was chosen as a risk variable because stakeholder input and prudency recommended the evaluation of the potential effects of a carbon price. Currently, there is discussion at state and national levels about the enaction of a carbon price as a way to meet clean energy goals such as the Paris Climate Agreement targets. While there has been significant discussion regarding the enaction of a carbon price, there continues to be no firm consensus regarding the mechanism, timing, or value. Therefore, the Company did not include a carbon price in any of its base scenario or sensitivity modeling, but instead included a carbon price in risk analysis modeling by applying three different potential carbon price forecasts to the Optimal portfolios, PCA, and Alternate Plan.

DR programs were chosen as a resource in many of the optimization portfolios developed as part of this IRP. The selection of these resources in either Optimal portfolios, the PCA, or Alternate Plan does create some level of reliance on these programs to respond when called upon in order to meet certain peak demand hours over the course of the study period. In order to evaluate the level of risk this may pose to the Company, the responsiveness of DR programs was chosen as a risk variable, and modeling runs were conducted that reduced the number of hours per year that customers responded when a DR event was called.

Q. Please describe why these variables were evaluated using a deterministic risk analysis instead of a stochastic risk analysis.

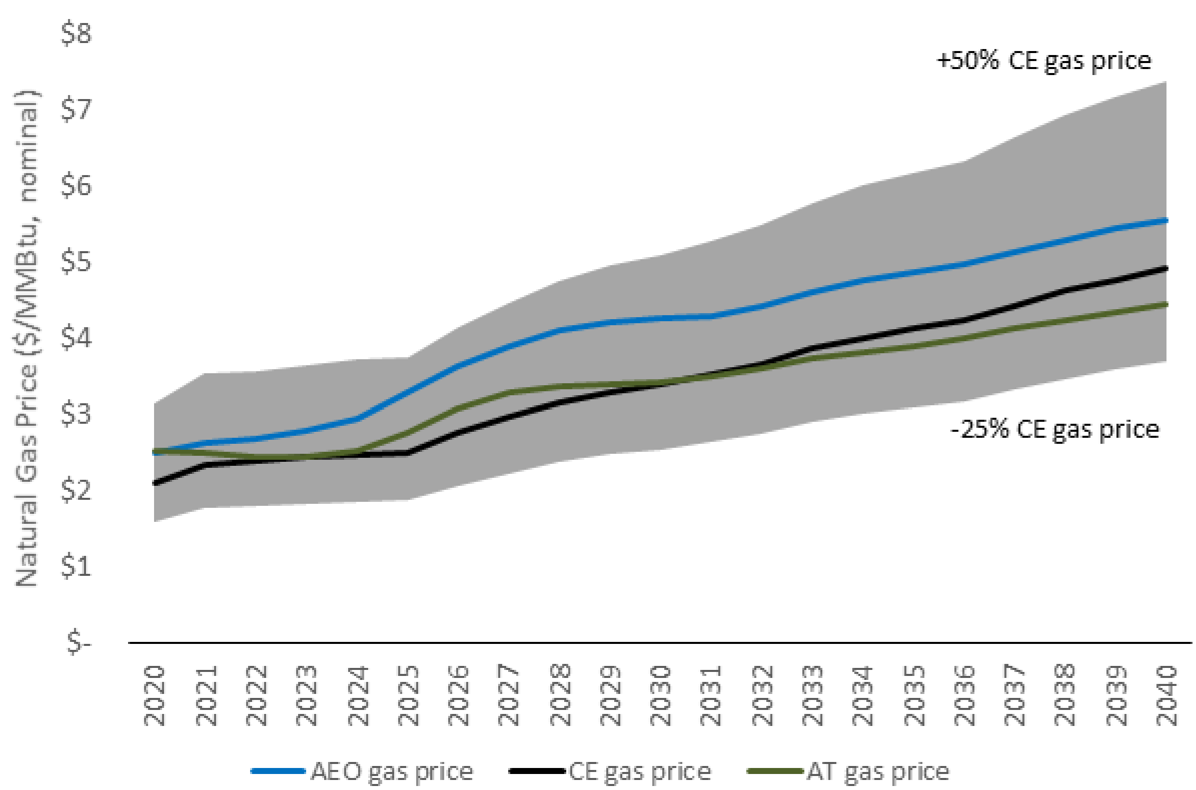
A. The use of both stochastic and deterministic risk modeling allowed the Company to perform a robust risk analysis while optimizing modeling run time and the quantities of data that were generated. Identified fluctuations in natural gas prices were already utilized in the NPV review of portfolio optimizations, an additional element of the Company's risk assessment methodology, and so these same fluctuations could be applied to risk analysis evaluation. For carbon pricing, the application of specific forecasts that identified key start dates and pricing levels allowed the Company to evaluate more specific expectations with regard to potential futures involving a carbon price, as opposed to random application of start dates or pricing levels. Finally, to evaluate the risk associated with the responsiveness of DR programs when called on, it was most appropriate to evaluate levels in responsiveness that were most likely to cause an impact to the cost or reliability of a portfolio, and so the extreme of 0 hours of DR as well as less than half the expected amount of DR (10 hours) were evaluated.

Natural gas prices, carbon prices, and DR availability were all evaluated in the risk analysis utilizing the Aurora model to perform a range of sensitivity analyses using an identified series of fluctuations from base forecasts.

Q. Please describe the range of natural gas prices that were evaluated in the risk analysis.

A. Based on whether the scenario used the Company's natural gas price projections (CE scenarios), the EIA 2020 AEO reference case ("AEO scenarios"), or the EIA's 2020 AEO High Gas and Oil supply case ("AT scenario"), the identified natural gas price forecast was incrementally adjusted by -25%, 0%, +25% and then +50% to evaluate each resource portfolio against a wide range of natural gas prices. A visual respresentation of the range of natural gas prices evaluated can be found below in Figure 6.

<u>Figure 6: Natural Gas Prices Included in 2021 IRP Analyses</u>



Q. What was the source used to determine the range of natural gas prices evaluated?

A. As discussed by Company witness Walz, three natural gas price forecasts were developed in this IRP. The AEO scenarios utilized the EIA 2020 AEO, the CE scenarios utilized the

Company's natural gas price projections, and the AT scenario used the EIA 2020 AEO High Gas and Oil Supply forecast. The use of specific, identified percentages allows the Company to evaluate a suitable range of potential changes in natural gas price over the study period. A future that maintains high supplies of natural gas will depress the price of natural gas, which in turn depresses energy prices. The -25% natural gas price sensitivity reflects this potential future, and evaluates a resource portfolio at a natural gas price that is less than the lowest base forecast utilizied. Alternatively, a future where natural gas supply is limited and/or in high demand will create an increase in natural gas prices, which in turn can lead to higher energy prices and exposes the Company and customers to increasing costs. The +25% and +50% natural gas prices are utilized to measure the level of exposure created in this situation, and evaluate which portfolios are more susceptible to this risk. As an increase in these costs can have a significant effect on customer affordability, the Company performs natural gas price risk analysis at both +25% and +50% of the base forecast in order to ensure that a high level of potential risk is evaluated when making retirement decisions as well as evaluating Optimal portfolios, the PCA, and the Alternate Plan.

Q. What resources were evaluated for natural gas price fluctuations in the risk analysis?

A. All natural gas-fired generating units located in all MISO LRZs were evaluated for changes in natural gas price, for all years of the study period.

Q. Please describe the range of carbon prices that were evaluated in the risk analysis.

A. The Company did not include a carbon price in any of its base scenario or sensitivity modeling. For the purposes of evaluating carbon prices as a part of risk assessment, the

Company utilitized three forecasts. The Base forecast was sourced from the IHS Markit 2019 - North American Power Planning Case. The High forecast was sourced from the EIA 2020 AEO. The Medium forecast was sourced internally by the Company as a blend of the Base and High forecasts in terms of starting year and $/short ton applied. The justification for the forecasts used in carbon price risk analysis are provided in the testimony of Company witness Heather A. Breining. Exhibit A-24 (HAB-3) provides the carbon price forecasts utilized in risk analysis.

Q. Were any other modifications made when evaluating the impacts of carbon pricing in the risk analysis?

A. Yes, a “must-run” designation was turned off for all thermal generating units in the model where initially designated. This change in designation allowed the Aurora model the option to choose to either dispatch that thermal unit under the assigned carbon price, or remove the unit from service when it is unecomomic and choose to dispatch other resources or purchase energy from the market.

Q. Please describe the range of DR availability that was evaluated in the risk analysis.

A. For DR resources in the Aurora model, the baseline outlook assumes that no more than 40 hours of interruption will occur in each year of the study period. Aurora schedules these hours by looking ahead and identifying the highest demand hours for each year, and then scheduling the dispatch of DR economically during the identified hours. For the purposes of risk analysis, the number of hours that DR resources could be dispatched was reduced to 10 hours, and then to 0 hours. As discussed earlier in this section, this reduction in hours represents a lack of customer response during DR events and therefore a reduction in the availability of DR to reduce peak demand levels.

Q. What was the source used to determine the range of DR availability evaluated?

A. The choice of 0 hours and 10 hours was determined internally by the Company as an appropriate range of the potential lack of customer responsiveness that could create risk in meeting peak demand levels or impacting the cost or reliability of a resource portfolio.

Q. What resources were evaluated for DR availability in the risk analysis?

A. The availability of DR was adjusted for all Company DR resources in the model, for all years of the study period.

SECTION VI: RISK ASSESSMENT MODELING RESULTS

Q. What were the results of the optimal portfolio risk assessment modeling, where the optimized plan for each scenario was modeled through all other scenarios?

A. Please see Exhibit A-12 (STW-9) for the results of the optimized portfolio risk assessment modeling.

Q. What were the results of the risk assessment modeling?

A. Please see Exhibit A-21 (AKM-1) for the results of risk analysis on the Optimal plans, PCA, and Alternate Plan. Results for electric demand, renewables availability, and thermal generator availability are presented as box and whisker plots showing the utility cost impact of each risk iteration. The results for natural gas prices and carbon prices are presented as scatter plots showing the NPV impact of each sensitivity analysis performed. No exhibit is presented for DR availability as the impacts of DR availability as an individual risk variable were marginal for all portfolios and did not result in a significant impact on NPV.

In order to isolate the impact of the risk variable, all risk analysis modeling was performed at 0% of the MISO Cost of New Entry ("CONE").

SECTION VII: RISK ASSESSMENT MODELING CONCLUSIONS

Q. What conclusions can be drawn from the risk assessment performed on demand?

A. Overall, similar impacts were seen across all resource portfolios evaluated for varying levels of electric demand. The Alternate Plan does experience a wider range of potential impacts than seen in the PCA, indicating that the Alternate Plan is more susceptible to cost impacts under fluctuations in demand. This is a result of the Alternate Plan relying more heavily on market purchases in the outer years of the study period after baseload generation resources such as Campbell Units 1 and 2 retire and the Midland Cogeneration Venture Limited Partnership PPA expires. In risk iterations in which electric demand is increased, energy prices are likely to increase and market purchases will grow more expensive. The Alternate Plan relies more on these market purchases to meet demand than the PCA, and therefore is more impacted than in the PCA when demand increases and market purchases become more expensive. As an illustrative example, in 2032 of the base case, Alternate Plan purchases from the market are nearly 10% more than the PCA in order to meet electric demand in that single year. This is prior to any application of increased demand from risk analysis. In risk iterations that increase demand, the volume of market purchases required in the Alternate Plan would increase further, leaving the Alternate Plan susceptible to the higher market prices that are likely to occur in this situation.

During the course of performing stochastic risk analysis electric demand on the Optimal Portfolios, PCA, and Alternate Plan, when demand reached a risk factor of 0.17 (indicating an increase to electric demand of 17%) or higher, loss of load events were seen in all portfolios. For a definition of a loss of load event, please see the testimony of

Company witness Walz. The appearance of loss of load events when electric demand is isolated as a risk variable indicates that there is a risk to reliability for all portfolios evaluated in this IRP if electric demand were to increase dramatically over the study period. It is worth noting, however, that all risk analysis was conducted on fixed resource portfolios, meaning that during stochastic risk analysis the Aurora model could not build additional resources to address increased demand levels as reliability limits were reached. In the Carbon Reduction scenario discussed by Company witness Walz, a sensitivity was performed that applied significant growth in electric demand due to electrification. This sensitivity allowed the Aurora model to build more resources to meet the identified increases in demand, and therefore no loss of load events were seen in this sensitivity.

Q. What conclusions can be drawn from the risk assessment performed on solar and wind resource availability?

A. Similar impacts were seen across all resource portfolios evaluated for the availabity of solar and wind resources. All resource portfolios evaluated for this risk variable contain similar penetrations of solar and wind resources over the course of the study period, and therefore similar impacts to the base NPVs are seen for each portfolio across the scenarios evaluated. If the availability, and therefore energy provided, from solar and wind resources is higher than expected, this has a positive impact on customer costs because these resources dispatch at low operating and maintenance costs, driving affordability and the cost effectiveness of the resource. If, however, solar and wind resources are not able to dispatch at their projected capacity, due to either persistent unfavorable weather conditions, unexpected outages, or maintenance, a portfolio that contains a higher percentage of these resources is at a higher risk for unfavorable cost impacts. This is because, if the expected availability and output from these resources does not materialize at the levels expected, the Company may need to purchase additional energy from the market on the day of need, exposing itself and customers to more expensive market prices.

An additional factor contributing to the lack of difference between portfolios is the fact that the solar and wind resources evaluated for availability are not correlated with each other. In the Monte Carlo simulations performed for each identified resource portfolio, solar and wind resources were allowed to fluctuate independently of each other over the course of the study period. While this was done to address the unlikeleness of weather patterns being the same across all locations in Michigan, which would result in all solar or wind resources experiencing the same lack of availability, an identified level of correlation would allow for the impacts of this risk variable to be further evaluated. The Company looks forward to continuing its build-out of solar and wind resources as part of its long-term energy planning processes, and continuing to improve the best methods to evaluate the risk of availability from intermittent resources.

Q. What conclusions can be drawn from the risk assessment performed on thermal generator availability?

A. The impact of fluctuations in thermal generator availability is not significant for any of the portfolios evaluated. A very small range of cost impacts are seen when the capability of a coal-fired or natural gas-fired unit is randomly reduced during the risk simulation. This is due to the fact that the stochastic risk analysis for thermal generator availability is performed on the entire 21-year study period of the IRP. The potential reliability or short term cost impacts occurring from the unexpected outage of a baseload generating unit are more diluted when viewed only as an overall impact to NPVs. The capacity sufficiency analysis ("CSA") performed by Company witness Walz evaluates the impacts of a thermal generator outage in specific hours of a given year, in combination with other risk variables, in order to evaluate the reliability of resource portfolios when thermal generator availability is impacted.

The second reason that a lack of overall cost impact is seen from evaluating the thermal generator availability is that the unexpected outage or reduction in capability of these resources only impacts energy costs, and in the case of all the fixed resource portfolios evaluated, replacement energy for these resources is available in the Aurora model at comparable costs. This means there is minimal risk in the energy market from the potential loss of availability of a Company coal-fired or natural gas-fired resource.

Q. What conclusions can be drawn from the risk assessment performed on natural gas prices?

A. As discussed by Company witness Blumenstock, overall economic analysis of the Alternate Plan versus the PCA indicates neutral to marginal customer cost/benefits. When isolating natural gas prices at 0% of CONE, for the purposes of risk analysis, similar results are seen. Under steady or declining natural gas prices, which is indicative of energy prices remaining stable, there are customer benefits to both the PCA and Alternate Plan. If natural gas prices, and therefore energy prices, were to increase significantly, then there is risk to customer costs under all scenarios, not just the PCA and the Alternate Plan.

Q. What conclusions can be drawn from the risk assessment performed on carbon pricing?

A. Carbon pricing has the potential to significantly impact utility costs in all of the resource portfolios evaluated. The resource portfolio most susceptible to the application of a carbon price is the Alternate Plan. This is due to the Alternate Plan maintaining coal-fired generation resources until nearly the end of the study period. The PCA, which retires all Company coal-fired generation by the year 2025, has a more narrow range of impacts from the three carbon price forecasts evaluated. The PCA also incurs significantly less additional costs under the applicaton of a carbon price when compared to the Alternate Plan. The High carbon price forecast, which begins in 2022, incurs nearly $3.8 billion more in utility costs to the Alternate Plan than the PCA. Even under the application of the Base level carbon price forecast, which applies a more conservative start date of 2030 and smaller $/ton impacts to each resource portfolio, the Alternate Plan incurs $679 million more in utility costs than the PCA.

For the Optimal portfolios, the resource porfolios selected under the BAU scenario have the highest potential impact from the application of a carbon price. Lacking the significant capital cost reductions for carbon free resources such as solar and batteries, the optimization portfolios for MISO Zone 7 in the BAU CE and BAU AEO scenarios contain more carbon emitting resources. When these resources then have a carbon price applied to them, this results in higher costs for market purchases starting in the year a carbon price is applied, which has a negative impact on both utility costs and customer rates. This is an additional reason that the Alternate Plan incurs higher customer costs under a carbon price than the PCA or Optimal portfolios, as the Alternate

Plan relies on a higher percentage of market purchases in the outer years of the study period than those resource portfolios that include the PCA's retirement decisions. The AT scenario has the lowest overall NPV impact from a carbon price due to the flat to declining load forecast used in this scenario, as well as due to additional economic thermal generator retirements that occur in MISO Zone 7 as a result of using the Aurora "can drop" feature in the modeling of this scenario.

Q. What conclusions can be drawn from the risk assessment performed on DR availablity?

A. The impacts from a reduction in the hours of DR availability are marginal. DR availability alone does not significantly affect the overall cost of any fixed resource portfolio modeled, as these resources provide their value in reducing peak demand at individual hours, certain days of the year as opposed to dispatching every day over the entire study period. Therefore, when isolated as a risk variable, a potential lack of DR customers responding when called upon during a DR event does not result in significant impacts to overall customer costs. The key metric to review when evaluating DR programs and risk is reliability, and whether the lack of response during a DR event can cause reliability issues or loss of load events. When isolated as a risk variable, the lack of DR availability does not cause loss of load events. Company witness Walz discusses the impacts that DR availabilty had on the CSA when combined with other risk variables and when each hour of a year is evaluated, and the resulting reliability of a resource portfolio when DR availability is reduced along with applying additional risk factors.

Q. What are the conclusions regarding risk analysis and the expected performance of the PCA?

A. The Company has performed a robust risk analysis that is consistent with the risk assessment methodology mandated by the Commission in Case No. U-18461. The risk assessment performed in this IRP supports the PCA as the best plan for Michigan. The PCA provides a resource portfolio that: (i) is robust enough to serve Consumers Energy's full-service electric customer demand during all hours, 365 days per year; (ii) stands up to potential significant increases in electric demand; (iii) delivers on generation diversity; and (iv) provides less financial risk to customers. The robust nature of the Company's risk assessment conducted for this IRP further establishes that the PCA represents the most reasonable and prudent plan to meet the energy and capacity needs of the Company's customers.

Q. Does this complete your direct testimony?

A. Yes, it does.

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 Approval of an Integrated Resource Plan	)	Case No. U-21090
under MCL 460.6t, certain accounting	)	
approvals, and for other relief.	)	
______________________________________	)	

DIRECT TESTIMONY

OF

THOMAS P. CLARK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

Q. Please state your name and business address.

A. My name is Thomas P. Clark, 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. In what capacity are you employed?

A. I am the Executive Director of Electric Supply.

<u>SECTION I: QUALIFICATIONS</u>

Q. Please describe your educational background.

A. I received the degree of Bachelor of Science in Engineering from Western Michigan University in 2004. Since 2010, I have been a Registered Professional Engineer in the state of Michigan. In December 2016, I received the degree of Master of Business Administration from the Ross School of Business at the University of Michigan Ann Arbor.

Q. Please describe your business experience.

A. In August 2004, I joined Consumers Energy as an Electric System Owner. In 2005, I accepted a position as an Engineer in Transactions and Resource Planning responsible for administration of the Resource Conservation Plan and the Qualified Facility Reduced Dispatch Agreements. In this role, I also provided assistance in proposal evaluation and the administration of power purchase contracts. In early 2009, I took on responsibilities associated with the Company's Renewable Energy Plan ("RE Plan" or "REP"), including the calculation of the Transfer Price associated with renewable energy and capacity and Renewable Energy Credit ("REC") tracking and forecasting. In June of 2013, I was assigned to the Smart Energy Department where I was responsible for the development and implementation of demand response ("DR") programs associated with the Company's deployment of Advanced Metering Infrastructure. In March 2015, I accepted the role of manager of the Company's Resource Planning department where I was responsible for all of the Company's short-, mid-, and long-term electric generation resource planning, including the development of the Company's integrated resource plans. In July of 2017, I added Real-Time and Day-Ahead Midcontinent Independent System Operator, Inc. ("MISO") Market Operations to my Resource Planning responsibilities. In March of 2021, I was promoted to my current role where I have responsibility for purchasing and transport functions for fuel for electric generation, interaction in the MISO markets, Power Supply Cost Recovery ("PSCR") activities, wholesale settlements and transactions functions, and contract strategy functions including distribution agreements, solicitations for energy and capacity, renewable energy compliance, and distributed generation programs.

Q. Have you previously presented testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I provided testimony in the following cases:

- Case No. U-15675-R, the Company's 2009 Power Supply Cost Recovery ("PSCR") Reconciliation regarding the portion of RE Plan costs to be recovered in the Company's PSCR Reconciliation for 2009;
- Case No. U-16300, the Company's 2009 Renewable Cost Reconciliation regarding renewable energy costs incurred in 2009;
- Case No. U-16543, the Company's RE Plan Amendment, regarding renewable energy purchase agreements and the portion of RE Plan costs forecast to be recovered as PSCR costs;
- Case No. U-16045-R, the Company's 2010 PSCR Reconciliation regarding the portion of RE Plan costs to be recovered in the Company's PSCR Reconciliation for 2010;
- Case No. U-16301, the Company's 2010 Renewable Cost Reconciliation regarding renewable energy costs incurred in 2010;

- Case No. U-16581, the Company's Biennial RE Plan Review, regarding renewable energy purchase agreements and the portion of RE Plan costs forecast to be recovered as PSCR costs;

- Case No. U-16432-R, the Company's 2011 PSCR Reconciliation regarding the portion of RE Plan costs to be recovered in the Company's PSCR Reconciliation for 2011;

- Case No. U-16655, the Company's 2011 Renewable Cost Reconciliation regarding renewable energy costs incurred in 2011;

- Case No. U-17301, the Company's 2013 Biennial RE Plan Review, regarding renewable energy purchase agreements, the portion of RE Plan costs forecast to be recovered as PSCR costs, the Company's expected compliance obligation, and REC forecast;

- Case No. U-17321, the Company's 2012 Renewable Cost Reconciliation regarding renewable energy costs incurred in 2012;

- Case No. U-18250, regarding the Company's electric generation resource planning process and its plan to meet customer demand requirements given the buyout of the Palisades Nuclear Power Plant Power Purchase Agreement ("Palisades PPA");

- Case No. U-18322, regarding the Company's benefit/cost analysis regarding the retirement of the Medium 4 Units; and

- Case No. U-20165, regarding the Company's 2018 Integrated Resource Plan ("IRP").

Q. What is the purpose of your direct testimony?

A. My direct testimony discusses the significance of the Company's reliance on the MISO markets under the Proposed Course of Action ("PCA") and the Alternate Plan ("AP"), as presented in the direct testimony of Company witness Richard T. Blumenstock. Specifically, I will discuss the benefits of the PCA over the AP and over the currently approved 2018 IRP Plan with regard to market reliance and exposure, and how changes proposed to the MISO market constructs may impact these plans. To support this discussion, my testimony will: (i) detail the current state of the MISO markets in which the Company operates; (ii) discuss unique aspects of MISO's resource adequacy construct, such as planning reserve margin requirements ("PRMR"), the capacity import and export limits ("CIL" and "CEL"), and the local clearing requirement ("LCR"); (iii) discuss MISO's proposed new resource adequacy construct; and (iv) discuss other market benefits of the PCA, including reductions in periodic outage length, shorter unit commitment time and cost, and capacity credit risk mitigation. My direct testimony is organized in the following manner:

- Market Reliance
- Other Market Benefits of the PCA
- The MISO Market and how Consumers Energy Participates
- Proposes Changes to the MISO Resource Adequacy Constructs

Q. Are you sponsoring any exhibits?

A. No.

<u>SECTION II: MARKET RELIANCE</u>

Q. Please provide an overview of the MISO market in which the Company operates.

A. MISO was established as the nation's first Regional Transmission Organization ("RTO") by the Federal Energy Regulatory Commission ("FERC") in 2001. MISO monitors the transmission network to strengthen reliability and ensure electric grid stability across 15 states and Manitoba as one integrated system.

Q. Please describe how the Company fits into the larger MISO market?

A. MISO has divided its footprint into 10 regions, or Local Resource Zones ("LRZs"), acknowledging the electric transmission system is constrained--typically by geography. Consequently, the designation of these LRZs generally follows state boundaries. The Lower Peninsula of Michigan is designated as Zone 7; the exception is a small part of southwest Michigan that is part of the Pennsylvania-New Jersey-Maryland ("PJM") market. Michigan's Upper Peninsula is connected with Wisconsin as part of Zone 2. The Company's entire service territory is in Zone 7.

Q. What services are available through the MISO market?

A. MISO provides all market services for energy, operating reserve, and transmission service in accordance with the terms of the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff ("MISO Tariff"). This includes operation and settlement of the Day-Ahead Energy and Operating Reserve Market ("DA Energy Market"), the Real-Time Energy and Operating Reserve Market ("RT Energy Market"), collectively referred to as the MISO energy markets. The DA Energy Market and the RT Energy Market are designed to work together to meet electric needs in the MISO footprint each day in the most economical manner. In addition to the MISO energy markets, MISO operates the Ancillary Services Market and the Capacity Market. The Company participates in all of these MISO markets.

Q. How does the Company define "market reliance"?

A. The term market reliance refers to the Company's utilization of the MISO markets to meet customer energy demands. MISO markets are intended to improve reliability and decrease costs for Load Serving Entities ("LSE") by enabling the efficient exchange of resources from one entity that has a surplus of resources to an entity that has a resource need. These markets are not intended to be relied upon for long-term capacity and energy needs.

Q. Is the Company concerned about over-reliance on the MISO Capacity Market?

A. Yes. MISO's Capacity Market is a residual market. As such, it is designed to enable the efficient transaction of relatively small amounts of capacity from one LSE with surplus capacity to another LSE with a shortfall. MISO's market relies on LSEs and/or state regulatory agencies to plan for capacity needs well in advance of the Planning Resource Auction ("PRA"). The residual nature of the MISO Capacity Market means the Company must not plan to rely on the MISO Capacity Market to meet persistent capacity needs because there may be insufficient capacity available to meet reliability requirements.

Q. Given that answer, how has the Company responded in this IRP?

A. The Company's PCA and AP are designed to limit the reliance on the MISO Capacity Market. The purpose of this IRP is to layout a capacity plan that ensures enough capacity to meet the Company's bundled retail customer load, plus reserve margin requirements, over the next 5, 10, and 15 years. As a result, the PCA and AP result in zero reliance on the MISO Capacity Market as constructed today.

Q. Are there changes proposed to the MISO Capacity Market construct that could result in greater reliance on the MISO Capacity Market?

A. As discussed in more detail later in my testimony, there are proposed changes to the MISO capacity construct that could impact the Company's market reliance. Specifically, MISO has proposed a seasonal capacity construct and changes to the capacity accreditation methods that pose significant risk to the AP and the 2018 IRP PCA beyond 2030.

Q. Does the Company address this risk?

A. Yes. One of the key advantages to the PCA recommended in this proceeding is that it addresses these concerns in both the short and long-term.

Q. How does the PCA address the risk of MISO Capacity Market changes?

A. The replacement of aging coal generation with much newer and more flexible gas generation allows the Company to continue the build out of renewable resources while mitigating the impact of MISO's seasonal construct and capacity accreditation changes on the supply portfolio. In particular, the gas generators can provide a backstop for solar generation in the winter months when solar produces much lower energy during peak periods and in the late evening hours during the summer when residential air conditioning load is high while solar generation begins to taper off. Both of these issues have been presented by MISO as reasons that the resource adequacy construct needs to change.

Q. Is the Company concerned about reliance on the MISO energy markets?

A. Yes. Since the development and approval of the Company's 2018 IRP there has been much consideration given to reliance on the MISO energy markets. The Company's approved PCA from 2018 called for significant increases in MISO energy market reliance over the course of the PCA. In fact, modeling in the 2018 IRP PCA suggested that as much as 41% of the Company's energy needs could come from the market by 2040. This increase in reliance was driven by the replacement of dispatchable fossil fueled generation resources with non-dispatchable intermittent renewable generation resources. One of the key questions that the Company endeavored to answer with the 2021 IRP is whether such market reliance was sustainable and, if so, what the consequences of continued significant reliance on the MISO energy markets would be.

Q. Is it feasible to rely on the MISO energy markets for up to 41% of the Company's energy needs, as proposed in the 2018 IRP PCA?

A. It depends. The Company determined that such heavy reliance on the MISO energy markets may be feasible assuming energy and capacity resources are added to the broader MISO marketplace that are capable of producing surplus energy that can be purchased to meet the Company's customer demand.

Q. What are the consequences of such significant reliance on the MISO energy markets for meeting customer's needs?

A. The consequences of large MISO energy market reliance is multifaceted.

First, the capacity additions required to allow for such significant reliance on the MISO energy markets are out of the control of both the Company and the Commission. As discussed above, MISO relies on the state regulatory agencies and individual LSEs to plan for future capacity needs. If other LSEs or MISO generation owners decided to add intermittent resources similar to those included in the Company's 2018 IRP PCA, reliance on the MISO energy markets to the extent included in that case may not be possible and, therefore, could create reliability concerns.

Second, hedging against the extreme volatility of wholesale energy markets is one of the key functions the Company offers for its customers. A responsible utility must ensure that it has sufficient resources to meet customer demand in most situations and use its ability to self-generate to hedge against market price extremes. Currently, the Company ***chooses*** to rely on the MISO energy markets when it is more economic to purchase energy than to produce energy from owned or controlled resources. In 2020, the Company purchased 18.3% of customer energy demand from the MISO energy markets, mostly because of the economic benefit of doing so. At nearly any time during these purchases, the Company had the ability to either: (i) bring generating units online that could produce the energy necessary to meet customer demand; or (ii) deploy demand-side resources to reduce needs such that market purchases could be reduced to zero. The market reliance required in the approved 2018 PCA may not always be a choice which could consequently affect the Company's ability to provide a hedge against extreme energy price volatility as it does today.

Third, reliance on MISO energy market purchases complicates and may prevent the Company from delivering on carbon reductions that meet the Paris Climate Agreement targets, Governor Witmer's MI Healthy Climate initiative targets, and the Company's Net Zero Carbon Emissions by 2040 targets. Because the Company is not able to choose which types of generating facilities are delivering energy purchased through the energy market there is no way to ensure that the purchased energy has a low environmental impact. In the MISO Futures Report - 2021[1] published in April 2021, MISO indicates three potential futures. Future 1 has a generation fleet consisting of 55% gas and 3% coal, Future 2 has a generation fleet consisting of 51% gas and 1% coal, and Future 3 has a generation fleet consisting of 31% gas. Even in the most aggressive carbon reduction future, Future 3, a significant portion of the MISO generation fleet relies on carbon emitting resources. This could prevent the Company from delivering on the carbon reduction targets identified above.

Q. How does the PCA proposed in this IRP address the MISO energy market reliance concern?

A. Under this PCA, the Company has endeavored to dramatically decrease carbon emissions associated with meeting customer energy needs while maintaining costs. As discussed by Company witness Blumenstock, this led the Company to contemplate a plan that retired all coal units as soon as practical. However, if the Company were to bring enough new renewable capacity online by 2025 to replace all retired coal resources (as unlikely as that

[1] MISO Futures Report538224.pdf (misoenergy.org)

may be), there would still be market reliance challenges. Consequently, the addition of gas generation resources allows the Company to address market reliance risk by replacing 2,626 MWs of older coal and oil dispatchable resources with 2,177 MWs of existing dispatchable gas resources. This will allow the Company to dramatically reduce carbon emissions while continuing to build a renewable portfolio consistent with the 2018 IRP and avoid the potential consequences of large MISO energy market reliance. Figure 13 in Company witness Blumenstock's testimony provides a visual representation of the energy reliance comparison between the AP and the PCA. In that comparison, the Company found that the purchase of the existing gas units cut the energy market reliance by 50%, reducing the Company's exposure to market price volatility and providing the Company with the ability to choose economic dispatch of the controllable generation or reliance on economic market energy.

Q. How has the Company quantified the significance of market reliance issues?

A. To help understand the significance of the market reliance issues, the Company examined data from the IRP model associated with the year 2032. This year was selected because, under the AP, this is the year where market reliance begins to become problematic. By comparing data from the AP and PCA we can demonstrate how the PCA addresses the reliance issues. Specifically, the Company examined data from the Loss of Load Expectation ("LOLE") analysis discussed by Company witness Walz.

Q. Please discuss the LOLE studies.

A. The LOLE studies conducted by the Company allowed the model to rely on the market as a firm resource up to 3,200 MW. This was the CIL identified by MISO for LRZ 7 at the time modeling for the IRP began. As discussed by Company witness Benjamin T. Scott, this assumption is valid because MISO determines the CIL by conducting a LOLE type analysis on LRZ 7 and adjusting generating resources until transmission limits are reached. Some reliance on the CIL as a firm resource is warranted. However, as noted by Company witness Scott, MISO performs this analysis only for the peak day. It is unclear what the maximum firm CIL may be on days other than the peak. Furthermore, the CIL is the import limit available to all LRZ 7. It is unlikely that the Company will have access to 100% of the CIL all the time. This is not to say that the Company's LOLE analysis was flawed. To the contrary, it is appropriate when considering the probability of firm load shed events to allow for reliance on the market. In fact, relying on the market during unexpected or unusual circumstances is one of the primary reasons to participate in a large regional market such as MISO. The Company examined the results of the LOLE analysis for the AP in the year 2032 and identified that there was a high likelihood of one loss of load event occurring each year even when assuming the entire CIL is firm capacity that can be relied upon all the time. In fact, by examining the LOLE analysis the Company determined that the AP on average relies on 32% of the CIL capability. This led the Company to ask what amount of market reliance was occurring outside of the extreme conditions in which actual loss of load was forecasted to occur. By further examining the data from the LOLE analysis the Company was able to determine that 2.2% of hours in 2032 required non-voluntary market purchases.

Q. Please explain the difference between "non-voluntary market purchases" and "voluntary market purchases".

A. As mentioned earlier, the Company currently possesses the necessary resources to meet customer demand but ***chooses*** to rely on the market when it is economically favorable for customers. Therefore, the Company's market purchases today are "voluntary". The Company chooses to purchase energy from the market instead of generating it with resources owned or controlled by the Company because there is an economic benefit to customers. Simply stated, the Company buys energy from the MISO market when it is the cheapest resource available to meet customer demand.

"Non-voluntary" market purchases refer to those market purchases that are made at times when the Company does not have sufficient resources available to meet customer demand. Under these circumstances the Company is not making an economic decision, it is purchasing from the market because that is the only option available to meet customer demand. To date, the Company has only ever experienced this condition under extreme weather conditions and/or when some amount of generation is unexpectedly unavailable. In 2032, under the AP proposed in this case, the Company would, on average, rely on 32% of the CIL capability and would rely on "non-voluntary" market purchases 2.2% of the time. With the PCA, specifically through the purchase of dispatchable gas resources, the Company can reduce market reliance. Under the PCA the Company, on average, will rely on only 17% of the CIL capability and would reduce "non-voluntary" market purchases to 0.5% of the time.

Q. Are "voluntary" market purchases preferred?

A. Yes. Voluntary market purchases represent the Company minimizing customer costs by leveraging the MISO energy market. Non-voluntary market purchases represent reliance on the MISO energy market as a last resort to meet customer demand. While acceptable in extreme conditions, MISO's market constructs are designed assuming a well-planned generation supply portfolio that does not include regular non-voluntary market reliance.

SECTION III: OTHER MARKET BENEFITS OF THE PCA

Q. What are the other market benefits of the PCA compared to the AP?

A. The PCA provides many market benefits compared to the AP including increased operating flexibility, reduction in planned outage time, and more capacity accreditation certainty.

Q. What are the benefits of increased operating flexibility?

A. Generally, natural gas combined cycle and simple cycle units have dramatically shorter startup and shut-down times compared to both the coal units and D.E. Karn ("Karn") Units 3 and 4. The shorter startup times mean lower startup costs and the ability to recoup those costs within MISO economic dispatch windows. This means there is less need for the Company to elect to start these types of units. The majority of the time, the MISO energy market will economically select the Company's gas units for startup. Also, because the units are designed to start and stop more often than coal units, it is reasonable to allow the market to select to decommit (or shutdown) the units based on the economic outlook for the generator. Stated simply, the Company can offer gas combined cycle and simple cycle units as "economic" in the MISO energy market. The Company is rarely able to do the same with its coal units. Because of the high cost and long duration of the coal unit's startup and shutdown, the MISO energy market cannot effectively commit these types of units appropriately. For this reason, the Company must develop a multi-week forecast of energy prices and select to commit and decommit coal units based on its own outlook. While the Company's willingness and ability to do this has delivered significant customer cost savings over the years, it is impossible to predict perfectly what conditions might arise over the coming weeks that will make what appears to be a great decision turn out poorly. By reducing reliance on longer-term energy price forecasts and relying more on the MISO energy market to commit and decommit generating units, the Company will improve the economic dispatch of its generation portfolio, which results in lower customer PSCR costs.

Q. What are the energy market benefits of shorter periodic outages?

A. The primary market benefit of shorter periodic outages is related to the risk of high market prices occurring during an outage. Shorter periodic outages mean less market price exposure. Periodic outages require significant planning, often a year or more in advance. The longer the outage, the greater the risk that the outage occurs during a period of unusual market conditions. If unusual market conditions drive energy prices up, then customers either miss out on the opportunity to benefit from the sale of energy at prices much higher than the cost of production or are required to purchase energy at prices much higher than the cost of production. Regardless of which situation arises, the net result is an increase in customer costs. Shorter periodic outages associated with natural gas units compared to older coal units means less market price exposure.

Q. How does the PCA provide more capacity accreditation certainty and why does that matter?

A. As discussed briefly related to Capacity Market reliance, there are two reasons the PCA provides more capacity accreditation certainty: (i) the proposed seasonal construct; and (ii) the Effective Load Carrying Capability ("ELCC") of Solar.

First, as discussed later in my testimony, MISO is pursuing a number of material changes to capacity construct currently in place. The most significant change is the proposal to move to a seasonal construct for capacity planning. A seasonal construct acknowledges that all hours matter and resources that are able to produce similar amounts of energy year-round will have greater value. There is still a tremendous amount of uncertainty regarding this change, but preliminary data indicates that solar capacity credit will be lower in winter months than currently awarded. Until there is more certainty regarding how much credit solar might receive in non-peak months, the Company should maintain a capacity plan that ensures it can meet planning requirements in all seasons.

Second, MISO has acknowledged that solar penetration has been insufficient to justify a dedicated ELCC analysis. In lieu of a dedicated analysis, MISO has awarded solar generators capacity credit consistent with other intermittent generating technologies. This method considers the production from a solar generator for hours ending 15 through 17 each weekday during the months of June, July, and August. This method results in capacity accreditation of approximately 50% to 70% of nameplate capacity. However, once material penetration of solar occurs within the MISO footprint, it is reasonable to assume that MISO will continue to refine its accreditation for solar. Data presented in the MISO Futures Report - 2021[2] indicated solar capacity accreditation could drop to as low as 30% as penetration increases.

Under the AP, the Company is confident that sufficient time will be available to understand the implications of these issues and address them before 2032. However, under the accelerated coal retirements included in the PCA, it is not prudent to assume that reliance on an entire solar replacement plan is viable.

SECTION IV: THE MISO MARKET AND HOW THE COMPANY PARTICIPATES

Q. Please further discuss the MISO Market and how the Company participates?

A. MISO provides all market services for energy, operating reserve, and transmission service in accordance with the terms of the MISO Tariff. This includes operation and settlement

[2] MISO Futures Report538224.pdf (misoenergy.org)

of the DA Energy Market and the RT Energy Market, collectively referred to as the MISO Energy Markets. The DA Energy Market and the RT Energy Market are designed to work together to meet electric needs in the MISO footprint each day in the most economical manner possible. MISO also operates the Ancillary Services Market ("ASM") and the Capacity Market.

Q. What function does the DA Energy Market have?

A. The DA Energy Market is a forward-looking market where energy and operating reserves for the *next day* are bought and sold. The DA Energy Market is a financially binding market that provides for economic and reliable operation of the electric system for the next operating day.

Q. How does the Company participate in the DA Energy Market?

A. The Company develops a forecast of expected demand for the next day and submits that as a load bid in the MISO DA Energy Market. The Company also develops a forecast of available generation resources and offers those resources to the DA Energy Market based on the variable costs required to operate them. MISO clears the Company's load bid and uses it, along with all the other LSE's that submit load bids, to award generation based on least cost.

Q. How does the RT Energy Market work?

A. The RT Energy Market takes place on the *actual* operating day and is designed to continuously balance electric supply and demand at the lowest cost while monitoring transmission system conditions.

Q. How does the Company participate in the RT Energy Market?

A. The Company provides updates to the load bid and generation offers throughout the day. MISO provides dispatch instructions to the Company's generation resources as appropriate to continuously balance supply and demand at the lowest cost.

Q. Please describe the utilities' method to determine whether to purchase energy rather than rely on DR.

A. The Company deploys DR resources either Day-Ahead or Real-Time. DR resources were deployed by the Company Day-Ahead when electric loads were expected to exceed a trigger condition. The Company typically deploys DR resources in Real-Time only during a MISO Maximum Generation Emergency Event Step 2.

Q. Please describe the methodology used to determine the trigger condition.

A. To support the Company's participation in the DA Energy Market, the Company develops a forecast of the hourly electric demand for each day. By reviewing historical peak demand, the Company identifies a demand level that, when exceeded, indicates DR resources should be considered and dispatched. For the summer of 2020, the Company calculated the trigger condition for Air Conditioning Peak Cycling ("ACPC"), Smart Thermostat Program ("STP") and Dynamic Peak Pricing ("DPP") based on a four-hour load forecast exceeding 27,000 MWh. The Company's residential ACPC program was available for up to 15 events over the summer. Ten system peak events can be called based on the trigger conditions described above. The remaining five events are reserved for MISO called emergency events. Similar to ACPC, the Company's STP was available for 14 events over the summer. Nine system peak events can be called based on the trigger conditions described above. The remaining five events are reserved for MISO called emergency events. The Critical Peak Pricing ("CPP") and Peak Time Rewards ("PTR") programs (collectively the DPP Program) were available for up to 14 events each. Given the limited number of events associated with these programs, the Company designs the triggers to call up to nine events each season.

Q. Please explain the Ancillary Services Market.

A. MISO's Ancillary Services Market ("ASM") is a collection of secondary services offered to ensure the reliability and availability of energy. The ASM provides for generation regulation, spinning, and supplemental services and has both a day-ahead and real-time component. Generation regulation serves to continually balance electrical supply and demand. Spinning reserves and supplemental services provide energy to meet demand on the system in the event of a sudden and unexpected loss of generation or transmission service.

Q. How does the Company participate in the ASM?

A. The Company offers generation into the ASM if it is available and responds to MISO dispatch instructions.

Q. Please explain the MISO Capacity Market.

A. MISO has a hybrid voluntary annual capacity construct in which all available generation in the MISO footprint participates in an annual PRA and must be available for all 8,760 hours of the MISO Planning Year. LSEs, such as Consumers Energy, can either choose to participate in the PRA or can pay a Capacity Deficiency Charge. The Planning Year ("PY") runs from June 1 to the following May 31. The forward Capacity Market is designed to ensure sufficient resources are in place to reliably serve load on a forward-looking basis. LSEs can meet their planning resource requirements by offering capacity resources and demand into the PRA through one or both of the following methods:

- Offering or self-scheduling capacity resources and bidding demand into the PRA; and
- Opting out of the PRA by submitting a Fixed Resource Adequacy Plan (“FRAP”), offsetting capacity resources and demand against each other.

Q. How does MISO determine its capacity needs?

A. MISO determines the appropriate amount of capacity required to maintain electric system reliability in accordance with the reliability requirements of the states and the regional reliability organizations that have jurisdiction within the MISO market region.

Q. What are the state and regional reliability requirements that affect the Company’s share of MISO’s capacity needs?

A. ReliabilityFirst, the regional reliability organization for the part of the country in which the company operates, has an established resource planning standard that allows for interruption of firm customer demand as a result of insufficient generation resources, known as LOLE or loss of load expectation (as discussed above), of no more frequently than one day in 10 years. MISO has adopted this standard as well and requires that all market participants secure resources that are adequate to achieve it.

Q. How does MISO determine the amount of resources that are needed to achieve these reliability standards?

A. MISO and its Loss of Load Expectation Working Group conduct an annual LOLE study to determine the MISO system Planning Reserve Margin (“PRM”) percentage and the LRZ specific Local Reliability Requirement (“LRR”) percentages. These are the reserve requirements that are necessary to achieve the one day in 10 years loss of load expectation discussed above. These percentages are applied to load forecasts submitted by LSEs to determine the amount of Zonal Resource Credits ("ZRCs") that each LSE is required to supply. Specifically, the LOLE determines, absent consideration of forced outages: (i) a capacity *Planning Reserve Margin*--the total resources across MISO's entire footprint that are required to meet load reliably through the year; (ii) a *Local Reliability Requirement ("LRR")*—the amount of resources that need to be deliverable within a specific LRZ to meet 1 day in 10 years reliability standard; (iii) the CIL—the number of resources that can be imported into the LRZ under peak conditions; (iv) the CEL– the number of resources that can be exported from the LRZ; and (iv) a *Local Clearing Requirement* ("LCR")--the minimum amount of resources that must be from the LRZ in order to meet 1 day in 10 years standard (calculated by subtracting the CIL from the LRR). These represent the targets necessary for MISO to satisfy ReliabilityFirst's capacity planning criteria.

Q. Please explain the LCR.

A. To ensure adequate supply and reliability, each LRZ has an LCR, or the minimum amount of resources that must be physically located within the zone taking electric transmission import capability into consideration. The LCR is equal to the LRR less the CIL for the zone and less non-pseudo tied exports for the zone. Non-pseudo tied exports are those exports in which MISO maintains dispatch control of the generating resource. If any LRZ does not meet its LCR in a given planning year, that Zone will clear at the Cost Of New Entry ("CONE") in the PRA. MISO determines the CONE values for its entire system and for each Zone annually and files the calculated values at FERC for approval.

Q. Please provide more information about CIL/CEL.

A. The CIL/CEL are effectively electric transmission import and export capability that can be reliably depended upon to transport power between zones during peak conditions. CIL and CEL are updated annually by the LOLE Working Group to capture changes in these capabilities as a result of modifications to the electric system.

Zone 7 has a CIL of 4,888 MW for the 2021/2022 PY and has maintained a CIL of at least 3,200 MW since 2018. This indicates the transmission system itself has the means to move substantial amounts of power into Zone 7. There are no physical transmission line constraints that limit the export of power from Zone 7.

More information about the Company's specific CIL/CEL data are discussed further in Company witness Scott's testimony.

Q. How are the MISO reserve margin percentages and CIL/CEL used to determine planning requirements?

A. MISO determines the PRM for the entire footprint. That PRM is applied to each LSE's load forecast individually to determine the PRMR for a specific LSE. Individual LSE PRMRs can be summed to determine the PRMR for a given LRZ and for the entire MISO footprint. For PY 2021/2022 MISO determined a PRM percentage of 9.4%. The PRMR for the entire MISO footprint was 133,902.7. The PRMR for LRZ 7 was 21,459.2. The PRMR for Consumers Energy was 7,574.7. The PRMR values represent the amount of firm capacity that is required to achieve the reliability standard assuming no transmission limitations exist between LRZs. Because transmission constraints do exist between LRZs, MISO calculates the LCR. The LCR is only applied at an individual LSE level if the LSE elects to satisfy the planning requirements using a FRAP. When meeting planning requirements using a FRAP an LSE must meet a load ratio share of the LCR. For example, for PY 2021/2022 LRZ 7 had a LCR of 19,710.1. If the Company had used a FRAP to meet 100% of its PRMR then MISO would have required 6,957.3 MWs of the Company's FRAP resources to be located in LRZ 7.

Q. Please explain ZRCs and how they are used by LSEs to meet MISO's resource adequacy requirements.

A. To facilitate compliance with the above discussed resource adequacy requirements, MISO has established fungible ZRCs, which are a measurement of each resource's available capacity after discounting for the resource's effective forced outage rate.

Q. How are ZRCs utilized in planning?

A. ZRCs represent 1 MW of unforced capacity from a Planning Resource. ZRCs are used by LSEs to meet Resource Adequacy obligations through a FRAP or by offering them into the PRA. ZRCs may be exchanged between Market Participants to fulfill bilateral contracts. Ultimately, the PRMR and the LCR discussed above are met by LSEs procuring (either bilaterally or through the PRA) a number of ZRCs equal to those requirements. For example, for PY 2021/2022 Consumers was required to FRAP or purchase through the PRA 7,574.7 ZRCs.

Q. How does the Company participate in the Capacity Market?

A. The Company typically secures 100% of the ZRCs necessary to meet the PRMR in advance of the PRA. These ZRCs come from Company owned and operated facilities, long-term Power Purchase Agreements, or bilateral capacity contracts. The Company then uses a FRAP and/or self-schedules the ZRCs to demonstrate that all load has been met. The vast majority of the ZRCs the Company acquires are located in LRZ 7 allowing the Company to meet all local resource adequacy requirements.

SECTION V: PROPOSED CHANGES TO MISO CAPACITY MARKET CONSTRUCTS

Q. Has MISO proposed changes to its resource adequacy construct that may affect the Company's planning?

A. Yes. MISO has proposed changes to its resource adequacy construct that could impact the Company's plans. The most significant of these proposed changes is the proposal to move from the Annual to the Sub-Annual (i.e. Seasonal) Resource Adequacy Construct and to adjust capacity accreditation to reflect seasonal availability[3].

Q Please discuss MISO's proposed Sub-Annual Construct.

A. MISO's Sub-Annual Construct breaks the calendar year into four "seasons". The current proposal is to have a Summer season (June – September), a Fall season (October and November), a Winter season (December – February), and a Spring season (March – May). MISO intends to calculate a PRMR and LCR for each season. These planning requirements would be developed based on LOLE analyses for each season. This construct basically replicates the annual process in use today for each of the four seasons. To facilitate the implementation of seasonal RA requirements MISO also needs to create seasonal accreditation criteria. This is particularly relevant for intermittent generation which has historically received capacity credit based on performance over MISO's peak load days during the summer.

[3]https://cdn.misoenergy.org/20210521%20RAN%20Workshop%20Sub-Annual%20Construct%20Presentation552959.pdf

Q. Why is MISO proposing these changes?

A. MISO cited five trends impacting resource adequacy:

Trend 1: Aging and retirement of the portfolio's generating units and the resulting impact on MISO's operations, requiring MISO to operate with less available capacity than in the past. The effect is to reduce redundancy provided by excess resource availability.

Trend 2: Outage correlation. The MISO system has year-round load and supply needs but is planned with a summer-focused capacity commitment. Lower overall capacity levels and higher outage rates have reduced available capacity in non-summer periods and, as a result, MISO has seen outages during non-summer periods imposing a growing challenge to ensuring sufficient available capacity in those periods. A dramatic increase in MaxGen[4] declarations outside summer suggests this trend impacts the sufficiency of energy availability.

Trend 3: Growth in demand-side and other emergency-only capacity as a percent of the overall portfolio which are not available to MISO's operators without the declaration of a MaxGen event under the existing framework.

Trend 4: Growing reliance on intermittent or unscheduled resources. MISO has historically relied upon forecast supply resources, which can often be uncertain or otherwise non-committed. While MISO has arrangements in place for purchase of emergency energy from neighboring systems during declared emergency conditions, availability of such energy remains highly uncertain during such conditions. While the

[4] Under emergency operations (typically under peak demand), MISO may issue generator operators an array of Max Gen protocols due to a shortage of capacity resources. Additional information available at https://cdn.misoenergy.org/Three%20Pager%20-%20MISO%20Operating%20Procedures%2009202018318965.pdf

regions have successfully managed these issues to date, MISO must now assess its ability to ensure sufficient conversion of committed capacity into energy in all time periods.

Trend 5: Growth of variable energy resources as a major element of the fleet. This increasingly important resource category by its very nature has different operational characteristics than legacy thermal resources. Renewable resources are accredited based on historic contribution during past system peaks, but there is no assurance that the accredited capacity will be available during an emergency. If wind or solar happen to contribute less during a particular time of need than in past years, the difference must be made up elsewhere. While it is also likely that, at times, these resources will help conditions by producing more than accredited, it is important to understand and plan for the operational implications of further renewable penetration. The impact of increased renewable penetration in the MISO footprint was further explored via MISO's Renewable Integration Impact Assessment ("RIIA").

Q. How would the Sub-annual Construct and capacity accreditation changes impact the Company's plans?

A. First and foremost, the uncertainty surrounding the final implementation of a seasonal construct creates some risk. Until MISO has completed implementation of these changes, it is impossible to know the exact impact, they will have on the Company's capacity plans. The assignment of PRMR and LCR by season will create additional planning requirements the Company will need to consider as it develops its future supply portfolio. Additionally, the capacity accreditation in the non-summer seasons is expected to have a material impact on the capacity credit awarded to solar generation. For example, MISO indicated in its most recent presentation on the Sub-annual Construct[5] that, for purposes of calculating seasonal import capabilities, solar unit output was assumed to be 0% for both the winter and spring seasons. While it is unlikely that solar will receive zero capacity credit for these seasons, it does clearly indicate that capacity accreditation for solar will be materially lower than the 50% assumed for summer capacity credit.

Q. How has the Company attempted to manage the potential impacts discussed above?

A. While there is insufficient information at this time to develop a plan that is guaranteed to address these changes, the Company's PCA does help mitigate the impact of changes to a seasonal capacity construct and intermittent generation accreditation. As noted earlier in my testimony, the replacement of aging coal generation with much newer and more flexible gas generation allows the Company to continue the build out of renewable resources while mitigating the risks created by MISO's proposed seasonal construct and capacity accreditation changes. In particular, the gas generators can provide a backstop for solar generation in the winter season when solar produces much lower energy during peak periods and in the late evening hours during the summer when residential air conditioning load is high while solar generation begins to taper off.

Q. Are there other changes to the resource adequacy requirements that could impact the Company's plans?

A. Yes. In addition to the significant changes to resource adequacy requirements discussed above, MISO is implementing a change to how planned unit outages are considered in the calculation of the LRR. MISO discusses the change in methodology from perfectly optimized planned outage scheduling to realistically optimized planned outage scheduling

[5] RAN Reliability Requirements and Sub-annual Construct (misoenergy.org)

in the PY 2021-2022 LOLE Study Report. These changes are expected to result in increases in LRZ 7 LRR which will offset any future increases contemplated to LRZ 7 CIL. As a result, the LRZ 7 LCR may not decrease even if the LRZ 7 CIL increases.

SECTION IV: CONCLUSION

Q. Please summarize your testimony.

A. In reviewing and analyzing both its previous and current IRPs, the Company has continued to consider all options that could accelerate the Company's clean energy transition, increase reliability, decrease market reliance, and minimize cost to its customers. As a participant in the MISO market, the Company has focused on adding generating resources—in this case natural gas plants--that can support its carbon reduction goals while easing the changing market conditions that will continue to evolve as the industry adapts to retiring fossil-fuel based units and increasing renewable energy assets. As highlighted in the PCA adding natural gas plants to the Company's portfolio mitigates some of the associated risk by having a resource that can remain a constant until the market definitively addresses the seasonal and capacity challenges of renewable energy. Finally, the addition of gas generation allows the Company more leeway in its future planning through reliable and generally nimble assets to call or offer at any time through greater increased operating flexibility and shorter outage length.

Q. Does this complete your direct testimony?

A. Yes, it does.

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 Approval of an Integrated Resource Plan	)	Case No. U-21090
under MCL 460.6t, certain accounting	)	
approvals, and for other relief.	)	
______________________________________	)	

DIRECT TESTIMONY

OF

HEATHER A. BREINING

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

Q. Please state your name and business address.

A. My name is Heather A. Breining, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Senior Engineering Technical Analyst III in the Environmental Services Department.

Q. Please describe your educational background and work experience.

A. In 2001, I earned a bachelor's degree in mathematics with a minor in physics from Spring Arbor University. I have been employed by Consumers Energy for 20 years in various areas including Environmental Services, Transaction Strategies, and Resource Planning.

Q. What are your responsibilities as a Senior Engineering Technical Analyst III?

A. I am responsible for evaluating and analyzing potential compliance options with environmental regulations and/or legislation and assuring that Consumers Energy's capital expenditures for environmental compliance are technically sound, economic, and complement the broader corporate strategy related to delivering safe, reliable, clean, and affordable energy. In addition, I am responsible for managing the Company's emission allowance portfolio and providing the necessary environmental documentation to support both Power Supply Cost Recovery and Electric Rate Case proceedings.

Q. Have you previously provided testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I testified in the 2018 Integrated Resource Plan ("IRP") Case No. U-20165 and the following electric rate cases: Case Nos. U-17990, U-18322, U-20134, U-20697, and U-20963.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to support the Company's IRP by describing the environmental regulations with which the Company's electric generating fleet must comply, the cost of compliance with those regulations, as well as the timing and the justification for the investments made to ensure environmental regulatory compliance, environmental justice, and the overall best plan for Michigan. My testimony and exhibits also support Company witness Sara T. Walz's Exhibit A-4 (STW-1).

Q. How is the remainder of your testimony organized?

A. My testimony is organized by the following sections:

Section I: Environmental Regulations and Compliance Strategy – Air Quality

Section II: Environmental Regulations and Compliance Strategy – Water

Section III: Environmental Regulations and Compliance Strategy – Waste

Section IV: IRP Emissions Outlook

Section V: Environmental Justice

Section VI: Corporate Clean Energy Goals

Q. Are you sponsoring any exhibits with your testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-22 (HAB-1)	AQCS Project Summary Table;
Exhibit A-23(HAB-2)	Projected Capital Expenditures;
Exhibit A-24 (HAB-3)	Carbon Price Forecasts Evaluated in IRP Risk Analysis;
Exhibit A-25 (HAB-4)	5-Year IRP Annual Emission Projections;
Exhibit A-26 (HAB-5)	Proposed Course of Action ("PCA") and Required Scenario Projected Emissions;

Exhibit A-27 (HAB-6)	Total Projected CO_2 Emissions Per Sensitivity Analysis and Percentage of CO_2 Compared to the Base;
Exhibit A-28 (HAB-7)	Emissions Accounting Methodology;
Exhibit A-29 (HAB-8)	Environmental Justice Results;
Exhibit A-30 (HAB-9)	Health Benefits Results; and
Exhibit A-31 (HAB-10)	Clean Energy Goal Comparison.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

SECTION I: ENVIRONMENTAL REGULATIONS AND COMPLIANCE STRATEGY – AIR QUALITY

Q. What is the purpose of Section I of this testimony?

A. The purpose of Section I is to describe the various environmental regulations related to air quality applicable to Consumers Energy that were a consideration in the development of this IRP.

A. Air Quality Regulation

Q. What is the Cross State Air Pollution Rule ("CSAPR")?

A. CSAPR is a federal air rule established by the United States Environmental Protection Agency ("EPA") that requires member states of the United States to reduce certain power plant emissions that contribute to pollution in other states. Specifically, CSAPR is a cap-and-trade rule that governs the emission of sulfur dioxide ("SO_2") and nitrogen oxides ("NO_x") from fossil-fueled Electric Generating Units ("EGUs") through the use of an allowance-based cap-and-trade program. Under this program, NO_x is regulated on both an annual basis and on a seasonal basis during the ozone season (i.e., May through September). Each allowance (annual or ozone) permits the emission of one ton of NO_x, with the emissions cap and number of allocated allowances decreasing over time. SO_2 is regulated on an annual basis only, with the emissions cap decreasing over time. Phase I of CSAPR was effective from January 1, 2015, to December 31, 2016, and Phase II became effective on January 1, 2017. In March 2021, in response to two Federal Court rulings, the EPA issued an update to the CSAPR rule that created a Phase III that became effective on June 29, 2021, for the 2021 ozone season. Although this revision reduces the available NO_x allowances for Consumers Energy's EGUs, the Company does not expect any significant change to cost or operational structure due to Phase III.

Q. What is "cap and trade"?

A. Cap and trade is a market-based approach to reducing emissions by providing economic incentives for achieving reduction in air emissions, wherein a "cap" on the emissions is determined and then divided into allowances. EGUs are then allocated a limited number of the allowances by a governing authority. This allocation authorizes EGUs to emit specific quantities of a specific pollutant, per time period. EGUs are required to surrender allowances in amounts equal to their emissions. EGUs whose emissions exceed their allocation must buy ("trade") allowances from others. Companies that exceed the cap pay penalties.

There are active trading programs for several different air emissions. As previously stated, NO_x and SO_2 are traded under the CSAPR program. There are also emission markets for greenhouse gas emissions, such as carbon dioxide ("CO_2"), in other states and countries, but not in Michigan.

Q. Can you please describe the Mercury and Air Toxics Standards ("MATS")?

A. MATS is another federal air rule finalized by the EPA in December 2011. It regulates emissions of mercury ("Hg"), acid gases, certain metals, and organic constituents through emission rate limits or the use of work practices for coal- and oil-fired EGUs. Unlike prior regulations, which permit allowance purchases or emission averaging over multiple units, MATS requires unit-by-unit compliance. Compliance with MATS was required by April 16, 2015, with a permissive one-year extension. The Company received an extension from the Michigan Department of Environmental Quality, now known as the Department of Environment, Great Lakes and Energy ("EGLE"), which pushed the compliance deadline to April 16, 2016. Consumers Energy has five coal-fired units and two oil-fired units subject to MATS.

Q. Can you please describe the Michigan Mercury Rule ("MMR")?

A. MMR is the Michigan counterpart to the federal MATS rule. Much like the federal MATS, the MMR was designed to regulate Hg air emissions in the state of Michigan. The MMR requires existing coal-fired EGUs to choose one of three methods to comply with the emission limits set forth in the MMR. Further, the MMR requires any new EGU to utilize best available control technology. EGLE ensured that the MMR had the same compliance deadline as the MATS rule, which was April 16, 2016.

Q. Please describe what regulations affect EGUs regarding greenhouse gases.

A. In October 2015, the EPA published rules intended to reduce carbon pollution from EGUs as described below. These rules were known as the Clean Power Plan ("CPP") Rules and were issued pursuant to Section 111 the Clean Air Act ("CAA"). Due to litigation challenges and administration changes, as described below, the only rule from the CPP that remains in effect is from Section 111(b) of the CAA for new and/or modified sources. This rule does not impact existing EGUs like the Company's D.E. Karn ("Karn")[1] and J.H. Campbell ("Campbell") plants unless they make a major modification.

Q. What is the status of the CAA Section 111 rules?

A. In July 2019, the EPA repealed the CPP and replaced it with the Affordable Clean Energy ("ACE") Rule, which focused on one component of the CPP -- energy efficiency improvements at coal-fired units. In response to legal challenges brought by environmental organizations, the D.C. Circuit Court of Appeals vacated the ACE Rule in January 2021. Due to these developments, there are currently no carbon regulations covering the existing fleet of Consumers Energy fossil fuel-fired generation facilities, absent a major modification. The Biden Administration, however, has communicated its intent to propose a rule, likely under Section 111(d) of the CAA, and potentially other CAA sections, to address carbon emissions from existing sources. The Company expects a proposed Section 111(d) rule addressing carbon emissions in late 2021 or early 2022.

Q. How does the uncertain status of greenhouse gas regulation of EGUs affect the Company's proposed IRP?

A. There are no expenditures related to greenhouse gas emissions compliance included in this IRP filing, as there currently are none identified for its existing fleet, or planned fleet, of generating units. That said, the Company will continue to monitor regulatory activity regarding greenhouse gas emissions standards that may affect EGUs and will incorporate any future compliance-related costs into future rate cases and future IRPs as appropriate.

[1] Also commonly known as the Karn-Weadock complex or facility. The Weadock coal-fired generation units previously located at the complex were retired in 2016 but features of the former Weadock plant remain.

Q. Are there any additional identified proposed air quality-related state or federal environmental laws or regulations that the Company considered when evaluating this IRP?

A. There are numerous other regulations, laws, and rules related to air quality including, but not limited to: (i) the Greenhouse Gas Reporting Program; (ii) the Boiler Maximum Achievable Control Technology standard; and (iii) the Regional Haze and Ozone Nonattainment Areas standard. However, no specific and/or significant actions are required of Consumers Energy regarding these identified regulations for purposes of resource planning pursuant to Section 460.6t. Consumers Energy will continue to comply with all applicable statutes and regulations.

B. <u>The Company's Air Quality Compliance Strategy</u>

Q. Describe Consumers Energy's historic Air Quality Compliance Strategy ("AQCS").

A. Consumers Energy has been reducing air emissions for years using various approaches such as fuel switching and installing air quality control systems. A summary of the pollution control equipment that has been installed to date is provided in Exhibit A-22 (HAB-1)

Q. How has the Company's AQCS benefitted customers?

A. Consumers Energy's efforts have prudently ensured compliance with applicable state and federal environmental 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. These investments have allowed the continued operation of Michigan-based generation, thus helping to ensure electric reliability and fuel diversity, which helps protect against significant fuel price fluctuations.

Q. Are there any additional pollution control equipment installations specifically related to air quality control that must be installed on any units within the Company's existing generation fleet for regulatory reasons?

A. No. There are no additional air quality control systems that need to be installed for compliance with the current air quality regulations. Some currently installed air quality equipment requires on-going capital maintenance for items such as fabric filter bags, cages and/or catalyst layers, etc. However, on-going capital maintenance is discussed by Company witness Norman J. Kapala.

Q. Are there any capital expenditures related to the air quality compliance that could be avoided if any or all of the Campbell units were to retire prior to May 2031?

A. Since there are no additional air quality control systems that need to be installed for compliance with the current air quality regulations, there would be no potentially avoidable capital expenditures from an environmental strategy perspective. However, from a plant operational perspective, as previously mentioned, there may be some on-going capital and/or operations and maintenance expenditures that may be avoidable. Company witness Kapala addresses the operational expenditures that are currently scheduled to be made, but that the Company would forego making in the event that one or more of the Campbell units were retired early.

Q. Are there any forecasted future expenditures associated with the Company's PCA to be compliant with air quality regulations?

A. No.

Q. Are there any forecasted future expenditures associated with the Company's Base and/or Alternate Plan to be compliant with air quality regulations?

A. No.

SECTION II: ENVIRONMENTAL REGULATIONS AND COMPLIANCE STRATEGY – WATER

Q. What is the purpose of Section II of this testimony?

A. The purpose of Section II is to describe the various environmental regulations related to water quality applicable to Consumers Energy that were a consideration in the development of this IRP.

A. EPA's Rule Regarding Section 316(b) of the Clean Water Act

Q. Can you please describe the EPA's rule regarding the Clean Water Act ("CWA") Section 316(b)?

A. In August 2014, the EPA published its final rule regarding Section 316(b) of the CWA ("316(b) Rule"). The 316(b) Rule established new standards for Cooling Water Intake Structures ("CWIS") at existing facilities. It became effective in October 2014 and applies to existing power generation facilities with a design cooling water intake flow greater than two million gallons per day ("mgd") from waters of the United States. It requires such units to reduce impingement and entrainment of fish and other aquatic organisms at the CWIS. Additionally, any facility subject to the 316(b) Rule with actual flows in excess of 125 mgd must provide an entrainment study with its National Pollutant Discharge Elimination System ("NPDES") permit application.

Q. What is the NPDES?

A. NPDES is a permit program implemented by the EPA and authorized state governments under the CWA. Under this program, industrial facilities that discharge pollutants into navigable waters must hold a permit from the EPA or authorized state agencies before they can discharge said pollutants. The permit specifies the process in which water pollutants may be discharged into navigable waters such as lakes, rivers, or streams as well as the technological features required to limit water pollution.

Q. What requirements does the 316(b) Rule impose on the Company?

A. The 316(b) Rule establishes national requirements which apply to the location, design, construction, and capacity of CWIS, and requires the use of Best Technology Available ("BTA") for minimizing adverse environmental impact. For impingement (where fish or other aquatic life are trapped against cooling water intake screens), the EPA has determined the BTA to be modified traveling screens, with fish return systems; however, six additional alternatives, with equal or better performance, are available for a facility to meet this standard. For entrainment (where fish or other aquatic life are pulled into or otherwise follow the flow of water into the cooling water intake), the EPA did not determine a BTA, because no one technology can be universally employed at all facilities. Rather, entrainment BTA is determined on a site-specific basis by the regulatory agency responsible for administering the NPDES program. The site-specific controls are justified through a series of prescribed studies, including, but not limited to, entrainment characterization; technical feasibility and cost evaluation; benefits valuations; non-water quality and other environmental impacts; and peer review. For the Campbell and Karn facilities, these prescribed studies were completed in 2017. Several studies required peer review, which was completed in the first quarter of 2018.

Q. Has the Company performed the prescribed studies and followed the BTA for minimizing adverse environmental impacts as required by the 316(b) Rule?

A. Yes. The Company submitted the prescribed studies and associated BTA demonstrations for Karn and Campbell to EGLE in 2018.

Q. What proposal for BTA did the Company submit to EGLE for compliance with the 316(b) Rule?

A. The Company's submittal seeks compliance for the entire Karn - J.C. Weadock ("Weadock") complex and the Campbell complex, rather than at the individual cooling water intake structures. For entrainment, the Company proposes that the existing cooling water intake systems at both generating complexes be considered BTA since the costs of additional technologies are wholly disproportionate to the benefits. In regards to impingement, the Company is advocating that at the Karn-Weadock complex BTA can be met by recognizing the flow reduction associated with Weadock Units 7 and 8 (part of the Karn-Weadock complex/facilities) retirement and with seasonal operation of pumps. Impingement BTA at the Campbell complex is met through a de minimus rate of impingement at the existing CWIS system.

Q. Has EGLE issued a final determination on these applications?

A. No. EGLE, however, has provided "interim" approval for the current NPDES permit cycle while it continues to review the application.

Q. When is the EGLE's final determination expected, and how will the final determination affect the Company?

A. The timing of EGLE's review of the submitted reports and proposed compliance strategies, and ultimate BTA determination, is at their discretion. At this time, the Company is anticipating that EGLE may address this determination during the next NPDES permit cycle, which begins in 2022 at the Campbell complex. EGLE can make BTA determinations for entrainment and impingement collectively, or separately. While the Company cannot predict EGLE's final determination, it is possible, for example, that EGLE could recognize the intakes at Campbell as BTA for entrainment and recognize the impingement as de minimis. In the event that EGLE disagrees with either, and an investment is warranted, the Company anticipates that new studies could be required and possibly requested as early as 2022 to support the NPDES permit renewal process and data collection.

B. <u>EPA’s Effluent Limitation Guidelines</u>

Q. Are there other water-related regulations to which Consumers Energy’s facilities are subject?

A. Yes. In November 2015, the EPA published the final Steam Electric Effluent Guidelines (“SEEG”) (also known as the “2015 SEEG Rule”). The 2015 SEEG Rule establishes effluent limitations based on Best Available Technology Economically Achievable (“BAT”) for existing sources. The 2015 SEEG Rule excludes oil-fired generation units and units with a nameplate capacity of 50 MW or less.

In September 2017, the EPA issued a final rule delaying the initial compliance deadline of the 2015 SEEG Rule from 2018 to 2020. This delay allowed the EPA to conduct a separate rulemaking to revise certain portions of the 2015 SEEG Rule. In October 2020, the EPA published a rule revising the 2015 SEEG Rule (“2020 SEEG Rule”). In the 2020 SEEG Rule, the EPA revised its technology-based effluent limitation guidelines applicable to Flue Gas Desulfurization (“FGD”) wastewater and Bottom Ash

("BA") transport water, but not for other waste streams covered by the 2015 SEEG Rule. Only BA transport water requirements will be discussed in this testimony, as Consumers Energy does not have any FGD wastewater streams.

The 2020 SEEG Rule identifies treatment using high recycle rate systems or dry handling as the BAT basis for control of pollutants discharged in BA transport water. According to the EPA, a high recycle rate system is a recirculating wet ash handling system operated such that it periodically discharges (i.e., purges) a small portion of the processed wastewater from the system. The EPA has found that this technology is available and economically achievable. In contrast to the 2015 SEEG Rule, which required a zero-liquid discharge (i.e., a 100% rate of recycling), the proposed rule allows facilities with a wet ash handling system to discharge up to 10% of the primary active wetted BA system volume on a 30-day rolling average under certain conditions.

The 2020 SEEG Rule also adds subcategories for high-flow units, low utilization units, and those that will transition away from coal combustion by 2028 and finalizes requirements that are tailored to facilities in these subcategories. Finally, it establishes the potential for new compliance dates, with approval from EGLE, as discussed later in my testimony.

Q. What BAT technologies have been defined for each waste stream?

A. The 2020 SEEG Rule, in addition to already regulating effluent limitations for several waste streams (such as low volume wastewaters), establishes BAT model technologies for the following waste streams:

Waste Stream	Existing Source BAT Model Technology
BA Transport Water[2]	High Recycle Rate System
Low Utilization EGU's[1, 2]	Surface impoundments + BMP plan
EGUs permanently ceasing the combustion of coal by 2028[2]	Surface impoundments
FGMC Wastewater	Dry handling
Gasification Wastewater	Evaporation
Nonchemical Metal Cleaning Wastes	No technology chosen – BAT for nonchemical metal cleaning wastewater is reserved

Note: (1) These waste streams are not generated at the Campbell or Karn facilities. (2) Recently revised/added as part of the 2020 SEEG Rule.

Existing source BAT effluent limitations for waste streams present at Consumers Energy facilities are summarized below:

Waste stream	Present At	Existing Source BAT Effluent Limitations
BA Purge Water	Campbell	Up to 10% allowance of BA purge water, from high recycle rate system, under allowable conditions. TSS Daily Max. = 100 mg/L TSS Monthly Avg. = 30 mg/L
BA Transport Water - EGUs permanently ceasing the combustion of coal by 2028	Karn	TSS Daily Max. = 100 mg/L TSS Monthly Avg. = 30 mg/L
Combustion Residual Leachate	Campbell	TSS Daily Max. = 100 mg/L TSS Monthly Avg. = 30 mg/L
Nonchemical Metal Cleaning Wastes	Campbell Karn	Reserved. No federal limits established. The EPA expects the permitting authority to examine the historical permitting record to determine how discharges of this waste stream should be permitted.

C. Timing – Implementation of the ELG Rule for SEEG

Q. What are the applicability dates for SEEG?

A. The current NPDES permit for the Campbell complex contains a compliance deadline of December 31, 2023, which is based on the 2015 SEEG Rule. Under the 2020 SEEG Rule, compliance with new BAT limitations for BA transport water does not apply until a date determined by the permitting authority that is "as soon as possible" beginning October 13, 2021, but no later than December 31, 2025. On January 11, 2021, Consumers Energy submitted a permit modification to EGLE requesting a compliance deadline extension to December 31, 2025 for the Campbell facility for three primary reasons: (a) to account for adequate planning and preparation of the Company's compliance with the rule; (b) sufficient time for engineering, design, and procurement; and (c) adequate time for construction and commissioning to ensure full compliance with the revised BAT limitations at Campbell. It is unclear whether EGLE will grant this request, as it is optional on its part.

Compliance with new BAT limitations for units ceasing coal combustion by 2028 requires submittal of a notice of planned participation ("NOPP") to EGLE by October 13, 2021, with progress reports submitted annually thereafter until unit operation has ceased.

Q. How does Consumers Energy intend to comply with the SEEG rules?

A. At the Campbell complex, the Resource Conservation Recovery Act ("RCRA") Coal Combustion Residual ("CCR") Rule requires unlined BA ponds not meeting performance standards to cease accepting CCR in 2018. As a result, Consumers Energy has replaced the unlined BA ponds with concrete tanks at Campbell and will continue to wet sluice BA.

Per the 2020 SEEG Rule, BA transport water at Campbell will need to be managed with a high recycle rate closed loop system. A discharge of BA purge water (blowdown stream) is allowable under certain conditions. The volume of BA purge water will be determined by EGLE but cannot exceed a 30-day rolling average of 10% of the primary active wetted BA system volume. The existing concrete tank system will be retrofitted as part of a high recycle rate closed loop system.

Q. If the PCA is approved as filed, would the Company be able to submit a NOPP for its Campbell units?

A. Yes. Because the PCA recommends closing all Campbell units by 2025, the Company would submit a NOPP by October 13, 2021, that would be conditional based on approval of the IRP and approval from the Midcontinent Independent System Operator, Inc. ("MISO").

D. <u>Capital Investments for 316(b) and SEEG Compliance</u>

Q. Are there any forecasted future expenditures associated with the Company's PCA to be compliant with these water regulations?

A. No. It is the Company's belief that any commitment made by the Company to retire the remaining coal units in 2025 would negate the need for investments to comply with 316(b) and SEEG. To date, no discussions regarding such a commitment have been made with EGLE, but it is the Company's belief that EGLE would be supportive of such. In total, this could reduce compliance costs by more than $97 million if the IRP is approved and retirement is approved by MISO.

Q. Are there any forecasted future expenditures associated with the Company's Base and/or Alternate Plan to be compliant with these water regulations?

A. Yes. As previously stated, a BTA determination for compliance with Section 316(b) is at the discretion of EGLE but anticipated as part of NPDES permit renewal in 2022. The Company is currently positioning itself to be able to react to EGLE's final Section 316(b) BTA determination. If entrainment BTA is required then the Company will move forward with the design and engineering of an alternate intake structure for Campbell Units 1 and 2 (i.e., the modification of the offshore intake for all units). If EGLE agrees that the existing cooling water intake at Campbell is BTA for entrainment, but requires the Company to then evaluate impingement, the 2021 budgeted dollars would then be spent on impingement studies. See Exhibit A-22 (HAB-1) for Section 316(b) capital expenditures.

For SEEG compliance, the Company conducted additional wastewater studies in 2020 to evaluate BA transport water chemistry, the results of which will be used in the design of a high recycle rate system. Additionally, wastewater studies were initiated to determine the level of required wastewater treatment at the Campbell site to maintain compliance with our NPDES permit discharge limits. Preliminary results indicated no further wastewater treatment was required; however, testing will continue through 2021 to account for seasonal and plant variability. In 2021, the Company will continue to collect data to characterize the BA transport water, which will be used to establish a basis of design for the high recycle rate system. The Company will procure engineering services in 2021 to design the high recycle rate system. The design will size the system for the expected volume of transport water, how often water will be discharged from the system, verify that non-ash contact water is not commingled with ash contact water, and start identifying equipment modifications needed in the plant. In 2022, the Company will begin the procurement of contractors and equipment such as pumps, piping, a storage tank, and any other equipment that 2021 design work determines is necessary for Campbell's closed loop system. See Exhibit A-23 (HAB-2) for SEEG capital expenditures.

SECTION III: ENVIRONMENTAL REGULATIONS AND COMPLIANCE STRATEGY – WASTE

Q. What is the purpose of Section III of this testimony?

A. The purpose of Section III is to describe the various environmental regulations related to waste disposal applicable to Consumers Energy that were a consideration in the development of this IRP.

Q. What are the applicable CCR management-related state or federal environmental laws, regulations, or rules that were considered when evaluating this IRP?

A. These laws, regulations, and rules include, but are not limited to, 40 CRF Part 257 and 261, Disposal of CCRs from Electric Utilities, published under Subtitle D of the RCRA. Michigan also regulates coal ash disposal under Part 115, Solid Waste Management (Part 115), of the Natural Resources and Protection Act of 1994 ("NREPA"), 1994 PA 451. NREPA includes amendments passed in December 2018 to align state requirements for coal ash landfills and impoundments with the federal rules. Michigan requires permits to construct coal ash landfills and surface impoundments and operating licenses to manage the operation and closure of coal ash landfills and impoundments. The federal rule contrasts this approach by providing a self-implementing framework that necessitates certain requirements must be certified by a qualified professional engineer on a schedule of compliance that is then maintained in an operating record and on a publicly accessible internet site by the owner or operator.

Q. Can you please describe the relevant parts of RCRA as related to CCR management?

A. The EPA finalized the Disposal of Coal Combustion Residuals from Electric Utilities rule in April 2015. This rule establishes requirements for CCR landfills and surface impoundments under Subtitle D of the RCRA, the nation's primary law for regulating solid waste. 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. Specifically, these rules contain construction and operation standards for applicable CCR units as well as closure and post-closure care standards. They prescribe procedures for corrective action and remediation of environmental impacts related to historical or ongoing operation of applicable CCR units. Those CCR units where environmental impacts have been documented could incur costs for corrective action and remediation regardless of the operational status of either the electric generating units or the specific CCR unit. The rule is considered self-implementing, meaning that affected facilities must certify compliance with the published standards and schedules and enforcement is through citizen suit.

Q. What is the Water Infrastructure Improvements for the Nation Act ("WIIN")?

A. The WIIN is an infrastructure appropriations bill signed into law in December 2016 authorizing water projects restoring watersheds, improving waterways and flood controls, and improving drinking water infrastructure. Section 2301 of this law provides a process to delegate authority for the regulation of coal ash management through a state permit program in lieu of the current enforcement of the federal rules through the RCRA Citizen Suit Authority, or by direct enforcement by the EPA. States may elect to submit an application to demonstrate evidence of a permit program or system of previous authorizations to the EPA for approval. The EPA must either approve the permit program, approve a partial permit program consisting of the elements that are found to be "equivalent to" or "as protective as" the federal rule, or enforce the rule through the enforcement authority granted under the WIIN Act unless the EPA develops a permit program through an appropriation. The EPA published a draft federal permit program (85 FR 9940) for public notice and comment in 2020, but publication of a final rule is still pending. The State of Michigan passed its own CCR state permitting program into law in December 2018, and subsequently submitted evidence of a state permit program to the EPA in February 2020 and continues to review the application in consultations with the EPA pending a completeness determination. In the interim, standards of the federal rule may be enforced through direct enforcement by the EPA or through the Citizen Suit Authority.

Q. How does Consumers Energy intend to comply with management of CCRs under the RCRA and Part 115?

A. Consumers Energy has certified compliance with the plans and reports required by RCRA, including initiating groundwater monitoring programs and closure for unlined CCR surface impoundments within the prescriptive 42-month self-implementing compliance schedule.

The approval of a State CCR permitting program would allow EGLE to issue permits under the authority of the solid waste management law (Part 115 of NREPA) to regulate compliance schedules and activities for CCR landfills and surface impoundments in lieu of the self-implementing compliance requirements and schedules under RCRA.

The Karn BA pond ceased operation in June 2018 and all CCRs were removed by October 2019. EGLE accepted documentation of removal of CCR from the pond in December 2020. The former unlined BA pond was replaced with a composite lined impoundment meeting the RCRA requirements and was put into service in June 2018. The approximately 171-acre Karn landfill completed closure activities through completion of construction for the final cover system in December 2019. EGLE accepted the certification of all phases of final closure in June 2020.

The Weadock landfill will continue to operate for the life of the Karn facility. As a result of the RCRA Rule, beginning in 2015, and continuing through 2016, efforts commenced modify the existing outlet structure and systematically draining ponded water out of low areas and backfilling with dry CCR to promote subgrade stabilization and surface drainage into perimeter ditches in anticipation of constructing the final cover. The modifications of the existing outlet structure to prevent surface run-on to the landfill and allow for gravity drainage of the interior of the disposal area, thus minimizing infiltration into the landfill and improving the subgrade to place the final cover upon construction. In 2018, a soil-bentonite slurry wall extension completing the full enclosure of waste footprint at the Weadock landfill was constructed, certified, and approved by EGLE. Completing the construction of the slurry wall provided complete containment of CCR materials as well as controls for potential sources of groundwater impacts. In 2020, Consumers Energy completed removal of CCR from the Weadock BA pond. EGLE subsequently accepted the documentation report confirming removal of the CCR in December 2020 in conformance with the EGLE-approved work plan.

In 2017, the Campbell facility completed construction to replace unlined BA ponds with concrete tanks. As a result, unlined BA ponds and an NPDES treatment pond were closed, so the electrical generating units will be able to continue wet sluicing BA to an engineered system that meets the design standards of RCRA. The concrete tanks provide a cost-effective, longer-term replacement to the CCR storage and NPDES ponds, enhance ground water protection and maintain the ability to beneficially use the BA.

Q. What are the capital investments specifically related to RCRA and Part 115 compliance?

A. Consumers Energy has completed the capital investments necessary for compliance with RCRA and state requirements. Additional capital for remediation systems will become their own assets (not an improvement to the disposal asset) and will be managed as an asset with Cost of Removal ("COR") obligations separate from the usable life of the landfill and/or surface impoundment. Future capital and/or O&M costs associated with RCRA and Part 115 can be found in the workpapers of Company witness Kapala (see Workpapers WP-NJK-1, 8, 9, 10, 22, 23, 24, and 25).

Q. Are there any CCR management-related expenditures that would be avoidable under the PCA?

A. Most of the CCR-related expenditure, both capital and COR, are unavoidable regardless of whether or not the units continue to operate since those costs are invested to bring those disposal units to closure; however, there are a few avoided costs that could be realized. For example, the Campbell site's avoided costs could be avoided due to the generation of less CCRs. This would likely reduce the number of cells and total area needed for closure. In Workpapers WP-NJK-22 and WP-NJK-24, Company witness Kapala estimates nearly $11.3 million in avoided costs related to additional cell construction and permitting at the Campbell site for the period from 2023 through 2027.

Q. Are there any new applicable environmental regulations the Company expects to be compliant with as a result of the PCA?

A. No. The Company's PCA eliminates coal-fired generation by 2025. In doing so, this essentially eliminates any potential future environmental regulatory burden associated with the Company's coal-fired generating units. At the Campbell site, it also minimizes current compliance costs since that landfill builds smaller cells and early cessation would result in fewer future cells constructed and less final cover to be installed. That said, the Company does expect future regulations affecting its natural gas-fired generating units; however, no such regulations have been released yet, and the Company cannot speculate as to their requirements at this time.

<u>SECTION IV: IRP EMISSIONS OUTLOOK</u>

Q. What is the purpose of Section IV of this testimony?

A. The purpose of Section IV is to describe the various air emissions impact associated with the Company's PCA and various scenarios and sensitivities that were analyzed and considered as part of this IRP filing.

A. <u>Scenarios and Sensitivities</u>

Q. What scenarios and sensitivities were included in the development of the modeling used in the IRP?

A. The scenarios and sensitivities modeled in the Company's IRP were defined within the Michigan Integrated Resource Planning Parameters ("MIRPP") document, pursuant to Public Act 341 of 2016, Section 6(t). The major input assumptions are summarized in Company witness Walz's Exhibit A-4 (STW-1), MPSC-Required Scenarios and Sensitivities.

Q. Were any other scenarios or sensitivities evaluated, in addition to those required by the Commission?

A. Yes. Three additional scenarios were added to the Company's IRP. The majority of input assumptions matched those of the Business as Usual ("BAU"), Emerging Technologies

("ET"), and Environmental Policy ("EP") scenarios, with one single input variable modified, which was the assumed cost of natural gas. The major input assumptions are summarized in Company witness Walz's Exhibit A-5 (STW-2), Consumers Energy-Specific Scenarios. The Company has abbreviated the names of the eight scenarios as follows:

- BAU AEO – BAU, built on required gas prices from the U.S. Energy Information Administration's ("EIA") 2017 Annual Energy Outlook ("AEO") reference case;
- EP AEO – EP, built on required gas prices from the EIA's 2017 AEO reference case;
- ET AEO – ET, built on required gas prices from the EIA's 2017 AEO reference case;
- CO_2 Reduction – this has underlying assumptions like the EP AEO, but with 1.5% load growth, CO_2 reduction targets by 2025 and the PCA as the basis of the new resource expansion plan;
- BAU CE – BAU, built on Consumers Energy's gas price projections;
- EP CE – EP, built on Consumers Energy's gas price projections;
- ET CE – ET, built on Consumers Energy's gas price projections; and
- AT – Advanced Technologies ("AT"), using the EIA's 2020 AEO high gas and oil supply case.

Q. Did the Company evaluate any scenarios or sensitivities that assumed a price on carbon?

A. Yes. The Company performed a deterministic risk analysis on the effects of a carbon price on a resource portfolio. Company witness Anna K. Munie discusses the analysis in more detail.

Q. Please describe the range of carbon prices that were evaluated in the risk analysis.

A. Consumers Energy did not include a carbon price in any of its base scenario or sensitivity modeling. For the purposes of evaluating the effects of a carbon price on a resource portfolio, the Company developed a Base, Medium, and High carbon price forecast and then modeled identified resource portfolios against all three forecasts to evaluate the effects of a range of potential carbon prices. The Base forecast utilized is the IHS Markit 2019-North American Power Market Outlook[2], the High forecast is the EIA 2020 AEO, and the Medium forecast was developed by the Company as a blend of the Base and High forecast in regard to starting year and $/Short Ton cost. A visual representation of the range of carbon prices evaluated can be found in Exhibit A-24 (HAB-3).

Q. How did the Company select the carbon pricing that was used in the risk analysis?

A. At this time, no regulatory framework currently in law includes any carbon pricing or emission restrictions applicable to Consumers Energy, such as a cap-and-trade or carbon tax program; therefore, the Company's base assumption assumes no price on carbon. Stakeholder input and prudency recommends modeling a price on carbon. The Company determined it would be prudent to run a risk analysis which includes a low, moderate, and high carbon price. It was recommended that IHS Markit carbon price forecast be used as the low carbon price, the Consumers Energy Adjusted carbon price forecast be used as the moderate carbon price, and the EIA High carbon forecast be used as the high carbon price.

IHS Markit assumes United States federal carbon policy takes the form of a price on power plant CO_2 emissions beginning in 2030. At the time the carbon price analysis

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was conducted, the outcome of the 2020 presidential election was not known. Thus, at that time, the Company had to consider two situations in an effort to try to determine the likelihood of future carbon legislation. First, if President Trump was to win re-election in 2020, the Company felt it was likely there would be no near-term carbon legislation and, thus, the 2024 election would then determine the outcome of carbon legislation. This scenario would make a price on carbon in 2030 appropriate and was selected as the Company's our low carbon price forecast.

Alternatively, if President Trump was to lose re-election in 2020, the Company felt there was a higher likelihood of proposed legislation and a price on carbon by 2025. As a result, the Company assumed the same trend in carbon prices as the IHS Markit forecast but accelerated the start to 2025. This Consumers Energy-adjusted IHS Markit forecast became the medium carbon price forecast.

For the high forecast, the Company selected the EIA forecast. In March 2020, EIA published a report in which they evaluated three pricing scenarios wherein an economy-wide implementation of a carbon fee went into effect in 2021, increasing 5% (in real dollars) per year and reach \$62, \$103, and \$144 per metric ton by 2050. This March 2020 report from EIA was the latest such price forecast available at the time the carbon price analysis was conducted.

Q. What were the results of the risk assessment modeling of the carbon prices?

A. Company witness Munie provides the results of the analysis on the optimal plans, PCA, and Alternate Plan on Exhibit A-21 (AKM-1), page 5.

B. Projected Emissions

Q. Please provide the annual emission projections for the first five years of the IRP study period differentiating between existing and new resources for the PCA for the following:

i) Tons of SO_2;

ii) Tons of NO_x;

iii) Tons of CO_2;

iv) Tons of particulate matter ("PM"); and

v) Pounds of Hg.

A. Please refer to Exhibit A-25 (HAB-4).

Q. Please provide the total projected emissions of the items listed below through the study period for the Company's PCA, as well as the scenarios identified within the MIRPP (three scenarios BAU-AEO, EP_AEO, ET_AEO) as approved in Case No. U-18418, or modified by Commission order:

i) Tons of SO_2;

ii) Tons of NO_x;

iii) Tons of CO_2;

iv) Tons of PM; and

v) Pounds of Hg.

A. Please refer to Exhibit A-26 (HAB-5).

Q. Please provide a comparison of total projected carbon emissions (CO_2) under each scenario and sensitivity analyzed, including quantifying the CO_2 emissions projected in each sensitivity as a percentage of the CO_2 emissions presented in the BAU case.

A. Please refer to Exhibit A-27 (HAB-6).

C. Emissions Accounting

Q. Please describe what is meant by the term "Emissions Accounting."

A. There are three main generation categories from which the Company serves its load: (i) owned generation; (ii) bilateral Power Purchase Agreements ("PPAs"); and (iii) purchases from MISO. There are times when Consumers Energy's available generation, both owned and PPAs, exceeds it load, and the Company sells the excess generation into the MISO market. Conversely, there are times when Consumers Energy's load exceeds available generation, and the Company needs to purchase from the MISO market. Properly quantifying both the historic and projected emissions associated with the electric generation used to serve the Company's customer load is an important component to projecting emissions in this IRP, as well as the Company's Clean Energy Goal. This issue is particularly important for the MISO market purchases because the Company does not know the generation source and its fuel type (e.g., coal, natural gas, or renewable) used to generate that energy; the Company is buying a generic megawatt-hour.

Q. Please describe the Company's emissions accounting methodology.

A. The Company has chosen the "specified portfolio" approach developed by the Electric Power Research Institute ("EPRI"),[3] which accounts for emissions of owned and operated resources, and any specified wholesale electricity procurement, plus emissions associated

[3] Please see https://www.epri.com/research/products/3002015044 for more information on this methodology.

with bilateral PPAs, and purchases from the energy spot market using a system average emission rate. Please refer to Exhibit A-28 (HAB-7) for additional details and assumptions regarding the Company's chosen emissions accounting methodology.

SECTION V: Environmental Justice Analyses

Q. What is the purpose of Section V of this testimony?

A. The purpose of Section V is to discuss how the Company considered environmental justice, including public health, when evaluating the Company's PCA.

Q. Did the Company use an environmental justice screening tool to identify any potentially vulnerable areas?

A. Yes. The Company used the EPA's EJSCREEN tool (https://www.epa.gov/ejscreen) to provide an initial screen for vulnerable areas. Analysis was performed using an impact area of 2 km and 10 km as shown in Exhibit A-29 (HAB-8). The Company considered any facilities that had an environmental or demographic "indicator" examined by the EJSCREEN above the 75th percentile to be a potentially vulnerable community. Our EJSCREEN analysis shows that none of Consumers Energy's existing fossil generation are located in areas above the 75th percentile for any indicator at either the 2 km or 10 km areas. That said, it identified three facilities that the Company is considering purchasing as part of the PCA that were above the 75th percentile for at least one indicator: Dearborn Industrial Generation ("DIG"), Covert Generating Facility ("Covert"), and Kalamazoo River Generating Station ("Kalamazoo River").

Q. Why did the Company decide on using the 75th percentile as an indicator for further consideration, analysis, or outreach?

A. The EPA's guidance on the use of the EJSCREEN tool suggested using the 80th percentile as the starting point for the purpose of identifying geographic areas that may warrant further consideration, analysis, or outreach. The use of an initial filter promotes consistency and provides a pragmatic first step for EPA programs and regions when interpreting screening results. After discussions with EGLE, the Company decided to err on the side of conservativism and opted to use the 75th percentile for identification of potential vulnerable areas.

Q. Did the Company perform any additional analysis related to the Covert, DIG, and Kalamazoo River facilities related to $PM_{2.5}$?

A. Yes. Because these facilities are located in potential vulnerable communities, the Company performed additional analysis to determine if the planning model, Aurora, suggested a material increase in their projected PM emissions in the PCA compared to the Alternate Plan.

Q. What additional analysis did the Company perform to determine if there was a material increase in the $PM_{2.5}$ emissions from the facilities identified at or above the 75th percentile?

A. The sites that warranted the additional analysis were facilities that the Company is looking to acquire in the PCA. It should be noted that the Company only forecasts filterable PM, not $PM_{2.5}$. The filterable PM emission rate and the $PM_{2.5}$ emission rate for gas-fired generating facilities are assumed to be equal for these facilities.

To determine whether a material increase in emissions would occur due to the PCA, the Company analyzed whether the purchase of these facilities would result in an increased dispatch, and subsequent increase in PM emissions. To do this analysis, the Company compared how those units were dispatched in the Aurora model for the Alternate Plan and the PCA under the BAU CE scenario assumptions. On average, the Covert facility's projected heat input and PM emissions each increased by 6.6%. The DIG facility's projected heat input increased by 1.7% and the projected PM emissions increased by 1.6%. The Kalamazoo River facility was projected to dispatch only a small fraction of time over the same time period and thus it was determined that the sample size was too small to provide reasonable results.

Q. Does the Company consider the projected increase in PM emissions shown by this analysis to be a material increase?

A. No. The Company considers any increase that is above any typical year-to-year variability to be material. Since the projected change in heat input aligned with the projected change in PM emissions, and since historic heat input data is readily available from the Clean Air Market Division website, a look at historic heat input variability was used to determine materiality. The historic annual heat input variability between 2016 and 2020 ranged from +2% to +7% for Covert. The historic annual heat input variability ranged from -8% to +9% for DIG between 2016 and 2020. Since their average projected PM emission increase percentages fell within their normal range of year-to-year variability, it was determined that the average projected increases were not material. In other words, if the Company acquires the DIG and Covert facilities, it is expected that those facilities will operate at levels similar to their operation before the Company acquired them. This suggests that the Company's PCA will not materially increase the emissions due to its acquisition of them.

Q. Did the Company examine whether the PCA will have any impacts on any nonattainment areas within the Company's electric service territory, or in the areas surrounding the facilities contemplated to be purchased under the PCA?

A. Yes, it did.

Q. What is a nonattainment zone?

A. A nonattainment zone, or nonattainment area, is any area that does not meet the national primary or secondary ambient air quality standard for a National Ambient Air Quality Standard ("NAAQS"). The NAAQS are health-based pollution standards set by the EPA.

Q. Does the Company currently own any generating facility that is located within nonattainment zone?

A. No. A map of Michigan's nonattainment zones can be found here: https://www.michigan.gov/documents/deq/deq-aqd-aqe-mi_attainment_status_map_407842_7.pdf.

Q. Are any of the generating facilities that the Company is proposing to purchase as part of the PCA located in nonattainment zones?

A. Yes. The DIG facility is located in Wayne County and is in an ozone nonattainment area and a SO_2 nonattainment area.

Q. Does the PCA negatively impact the nonattainment zones that DIG is located in?

A. No. As discussed above, the Company's modeling shows that DIG is projected to dispatch in similar fashion as it would have if the Company had not purchased it; therefore, no additional environmental impacts are anticipated. In addition, the Company will fully comply with all EGLE requirements related to these nonattainment zones.

Q. Would the Company be required to obtain any additional air or water-related permits for the facilities contemplated to be purchased under the PCA?

A. No. The Company would not be required to obtain any additional air and/or water permits due to the purchase of these facilities. The facilities' existing permits would simply need an administrative change transferring them into the Company's name. The Company will comply with all permits currently in place.

Q. Did the Company qualitatively assess different build plans to identify the potential impacts of the PCA on the identified vulnerable communities?

A. Yes, the Company examined, on a qualitative basis, the potential impacts of these facilities on various environmental factors such as water quality, water use, water discharge, waste disposal, air emissions, and public health.

Q. What did this analysis show?

A. The analysis showed that the projected heat input of the units in vulnerable communities was similar between the Alternate Plan and the PCA and, thus, there is no projected change in impact from these facilities. In addition, the PCA has a significant positive impact on water, waste, air emissions and public health for the state of Michigan as a whole.

Accelerating the retirements of the Company's remaining coal-fired power plants will dramatically improve Michigan's environment by:

- Reducing CO_2 emissions by more than 63 million tons from 2023 through 2040, a major reduction in this greenhouse gas;
- Nearly eliminating emissions from criteria air pollutants such as SO_2, NO_x, and PM from the Company's generating fleet;

- Eliminating emissions from hazardous air pollutants such as Hg from the Company's generating fleet;
- Reducing non-consumptive water use by more than 99% which equates to more than 220 billion gallons each year between 2023 and 2040 for plant cooling purposes; and
- Avoiding more than 3 billion cubic yards of coal ash waste from 2023 through 2040 and completely eliminating the generation of coal ash by 2025.

Q. As part of its environmental justice analysis, did the Company use any health benefits screening tools to evaluate the PCA's impact on public health?

A. Yes. The Company utilized the EPA's Benefits-Per-Ton approach to estimate the health benefits associated with emissions reduction.[4] This tool offers potential health benefits from two separate studies: Kewski et al. (2009) mortality study and Lepeule et al. (2012) mortality study.

Q. How did the Company evaluate the potential health benefits?

A. The Company evaluated the potential health benefits from both the Kewski et al. (2009) mortality study and Lepeule et al. (2012) mortality study while also utilizing both the 3% and 7% discount rates. While these studies estimate health cost savings in 2025 and 2030, the Company extrapolated the potential savings over the 2023 through 2040 timeframe. The health cost savings per ton were then multiplied by the delta in emissions between the Alternate Plan and PCA under the BAU CE scenario assumptions.

Q. What were the results of the health cost savings analysis?

A. This analysis shows that the SO_2 emissions reductions associated with the PCA will produce health cost benefits in the range of $403 million to $875 million in 2025, $326 million to $731 million in 2030, and $9.8 billion to $11.2 billion for the 2023-2040

[4] https://www.epa.gov/sites/production/files/2018-02/documents/sourceapportionmentbpttsd_2018.pdf

period overall. The NO_x emissions reductions associated with the PCA will produce health cost benefits in the range of $35 million to $78 million in 2025, $22 million to $48 million in 2030, and $557 million to $1.1 billion for the 2023 through 2040 period overall. The PM emissions reductions associated with the PCA will produce health cost benefits in the range of $26 million to $56 million in 2025, $1 million to $3 million in 2030, and $358 million to $837 million for the 2023 through 2040 period overall. Exhibit A-30 (HAB-9) shows the range of potential health benefits per pollutant over the study period, with the 3% discount rate.

SECTION VI: CORPORATE CLEAN ENERGY GOALS

Q. What is the purpose of Section VI of this testimony?

A. The purpose of Section VI is to describe the various corporate clean energy goals of Consumers Energy that were considerations in the development of this IRP.

Q. Does the Company have any environmental goals?

A. Yes. Consumers Energy operates under a triple bottom line of people, planet, and prosperity. The "planet" element of the triple bottom line represents the Company's commitment to protect the environment. This commitment extends beyond compliance with state and federal environmental laws to include voluntary sustainability efforts. The Company also considers climate change and other environmental risks in the Company's strategy development and business planning.

Through 2020, the Company's actions have reduced carbon emissions by more than 35% since 2005, reduced water usage by more than 30% since 2012, and avoided over 1.5-million cubic yards of landfill disposal since 1992. Additionally, Consumers Energy has reduced its SO_2, NO_x, PM, and Hg emissions by approximately 90% since 2005. These accomplishments have encouraged the Company to do more. In 2018, the Company also announced new five-year environmental goals for Michigan water, waste, and land, including:

i. Water: save 1 billion gallons of water;

ii. Waste: reduce waste to landfills by 35%; and

iii. Land: enhance, restore, or protect 5,000 acres of land in Michigan.

In February 2020, Consumers Energy announced a goal of achieving net-zero carbon emissions from its electric business by 2040. This goal includes not only emissions from the Company's owned generation, but also emissions from the generation of power purchased through long-term PPAs and from the MISO energy market. To the extent that Consumers Energy cannot fully eliminate its emissions by 2040, it will consider offsetting them through alternative measures, which may include carbon sequestration, methane emission capture, large-scale tree planting, or other measures. At this time, however, the PCA does not assume or plan for the use of carbon offsets. These goals represent Consumers Energy's further commitment to leave Michigan better than we found it.

Q. Why did the Company decide to commit to such an aggressive clean energy goal?

A. Consumers Energy is committed to creating a cleaner, more sustainable energy future for the state of Michigan. The Company is committed to this because: 1) customers and shareholders are increasingly asking for a reduction in the environmental impact of Company operations, with forward progress in this area appropriately balanced with cost; 2) the economics associated with decreasing the Company's environmental footprint have changed considerably making cleaner energy options the economic choice; and 3) it's simply the right thing to do for Michigan.

Q. How does the Company's PCA compare to other greenhouse gas reduction initiatives such as the MI Healthy Climate Plan, the Intergovernmental Panel on Climate Change ("IPCC") 1.5-degree Scenario and President Biden's Greenhouse Gas Reduction Target?

A. The MI Healthy Climate Plan is an executive order issued by the Governor of Michigan and outlines goals for Michigan to achieve economy-wide net-zero greenhouse gas emissions and to be carbon neutral by 2050. The executive order aims for a 28% reduction below 2005 levels of greenhouse gas emissions by 2025. To date, the Company has already surpassed the 28% reduction milestone for its owned electric generation. As shown on Exhibit A-31 (HAB-10), the PCA is projecting a 53% reduction below 2005 levels by 2025 with the inclusion of all generating sources used to serve the Company's customer electric load. In addition, the Company has set a goal to achieve net-zero carbon emissions from its electric business by 2040, which is 10 years earlier than the MI Healthy Climate Plan.

In the 2015 Paris Agreement, the countries participating in the United Nations Framework Convention on Climate Change agreed to hold the rise in global average temperature "well below 2 degrees Celsius above pre-industrial levels and to pursue efforts to limit the temperature increase even further to 1.5 degrees Celsius." Per the Summary for Policymakers IPCC report on the 1.5-degree scenario,[5] global CO_2 emissions have to decline by about 40 to 60% by 2030 from 2010 levels, and reach net-zero by 2050, to stay within the 1.5-degree scenario. As shown on Exhibit A-30 (HAB-9), the Company's PCA is well below the 2030 1.5-degree scenario target which, for illustrative purposes, was set at 50% below the Company's 2010 carbon emissions for all sources. In addition, the

[5] https://www.ipcc.ch/sr15/chapter/spm/

Company has set a goal to achieve net-zero carbon emissions from its electric business by 2040, which is 10 years earlier than the IPCC 1.5-degree scenario.

In April 2021, President Biden announced a new National Determined Contribution target for the United States under the Paris Agreement to achieve a 50 to 52% reduction from 2005 levels in economy-wide net greenhouse gas pollution by 2030. Again, the company's PCA is projected to be well below this target with a 62% reduction in carbon emissions by 2030 from 2005 levels.

Q. Does this conclude your direct testimony?

A. Yes.

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

DIRECT TESTIMONY

OF

KEVIN J. WATKINS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

Q. Please state your name and business address.

A. My name is Kevin J. Watkins and my business address is One Energy Plaza, Jackson, Michigan.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Senior Accounting Analyst III in the Corporate Property Accounting Department.

Q. Please describe your educational background.

A. I have a Bachelor of Science degree in Business Administration with a major in Accounting from Central Michigan University.

Q. Do you hold any professional certifications?

A. Yes. I became a Certified Depreciation Professional in 2012.

Q. What are your responsibilities as a Senior Accounting Analyst III?

A. My primary responsibilities are to support the Company's depreciation, regulatory, and rates filings and to account for book depreciation and asset retirement obligations. I also supervise the monthly close process of the Property Accounting system.

Q. Please summarize your prior professional experience at Consumers Energy before taking your current position.

A. I began my career with Consumers Energy in 1999 as an Accounting Analyst in the Financial Forecasting Department. In 2001, I accepted a position of General Accounting Analyst in the Corporate Property Accounting Department. Over the years, I have accepted increasing responsibilities and was promoted to Senior Accounting Analyst III.

Q. Have you testified previously before this Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I previously submitted testimony in Case No. U-16536 (Depreciation for Other Production – Wind Plant), Case No. U-16055 (Depreciation for Ludington Pumped Storage), Case No. U-16938 (Depreciation for Gas Utility Plant), Case No. U-17653 (Depreciation for Electric and Common Utility Plant), Case No. U-18127 (Depreciation for Gas Utility Plant), and Case No. U-20849 (Depreciation for Electric and Common Utility Plant).

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to present the projected unrecovered book balances of the D.E. Karn ("Karn") Units 3 and 4, J.H. Campbell ("Campbell") Units 1 and 2, and Campbell Unit 3 steam generating plants at December 31, 2022. Additionally, my testimony provides the projected decommissioning costs of the aforementioned plants and the Karn Units 1 and 2 steam generating plant. Finally, my testimony also provides projected ash disposal costs for Karn Units 1 and 2, Campbell Units 1 and 2, Campbell Unit 3, and the previously retired coal plants, B. C. Cobb Units 1 – 5, J.C. Weadock Units 7 and 8, and J. R. Whiting Units 1 – 3.

Q. Why are you presenting this information?

A. Book value and cost of removal, which includes the decommissioning and ash disposal costs, are depreciated over the life of the corresponding assets. Since the current depreciation rates were based on later retirement dates than what the Company is proposing in this case, these costs will not be fully depreciated at the time of proposed retirement.

Q. Are any other witnesses using the information provided in this analysis?

A. Yes, Company witness Jason R. Coker uses portions of this analysis in his testimony and exhibits.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-32 (KJW-1)	Projected Unrecovered Balances; and
Exhibit A-33 (KJW-2)	Projected Decommissioning and Ash Disposal Costs.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

<u>SECTION I: UNRECOVERED BOOK BALANCE</u>

Q. What is unrecovered book balance and how is it calculated?

A. Unrecovered book balance is the undepreciated capital investment. It is calculated by subtracting accumulated depreciation balances from plant in service balances.

Q. What are the projected unrecovered book balances of the Karn Units 3 and 4, Campell Units 1 and 2, and Campbell Unit 3 plants at December 31, 2022?

A. As shown in Exhibit A-32 (KJW-1), the unrecovered book balance is approximately $112 million at Karn Units 3 and 4, $514 million at Campbell Units 1 and 2 and $924 million at Campbell Unit 3.

Q. How did you calculate the December 31, 2022 projected unrecovered book balances for each site?

A. As shown in Exhibit A-32 (KJW-1), I started with the actual December 31, 2019 plant in service and accumulated depreciation balances. From there, I added the estimated plant in service additions for 2020, 2021, and 2022 to get the December 31, 2022 plant in service balance. Next, I calculated the depreciation expense by multiplying each year's average plant in service balance by the current depreciation rates. The 2020 - 2022 depreciation expense was added to the December 31, 2019 accumulated depreciation balances to get the December 31, 2022 accumulated depreciation balances. As explained previously, the unrecovered balance is calculated by subtracting the accumulated depreciation balances from the plant in service balances.

SECTION II: PROJECTED DECOMMISSIONING AND ASH DISPOSAL COSTS

Q. What are the total projected decommissioning and ash disposal costs for all of the units at the Campbell, Karn, and previously retired coal sites?

A. As shown in Exhibit A-33 (KJW-2), the total projected decommissioning costs are approximately $182 million and the total ash disposal costs are approximately $199 million for a total of approximately $381 million.

Q. What is the source of the projected decommissioning and ash disposal costs?

A. The projected decommissioning and ash disposal costs are presented in Case No. U-20849, the Company's electric and common depreciation case filed on March 1, 2021.

Q. Did you make any adjustments to the amounts included in Case No. U-20849?

A. Yes, I adjusted the projected decommissioning costs for Campbell Units 1 and 2, Campbell Unit 3, and Karn Units 3 and 4 to account for the earlier retirement dates.

Q. Why did you make the adjustments?

A. In Case No. U-20849, the estimated decommissioning costs were inflated to the previously planned retirement dates of 2031 for Campbell Units 1 and 2 and Karn Units 3 and 4 and 2040 for Campbell Unit 3. Since the Company is proposing retirement dates of 2023 for

Karn Units 3 and 4 and 2025 for the Campbell units, the decommissioning costs should only be inflated to those dates.

Q. Why are you including decommissioning and ash disposal costs for Karn Units 1 and 2 and ash disposal costs for the previously retired coal plants?

A. In Case No. U-20849, consistent with traditional utility depreciation accounting, the Company included these costs in calculating the proposed depreciation rates for the Karn Units 3 and 4, Campbell Units 1 and 2 and Campbell Unit 3 plants. Additionally, this approach is consistent with how the decommissioning and ash disposal costs were treated in Case No. U-17653, the Company's previous electric and common plant depreciation filing. In Case No. U-17653, this treatment was approved.

Q. What is traditional utility depreciation accounting as it applies to these plants?

A. In traditional utility depreciation accounting, the unrecovered book value remains in the steam plant depreciation reserve (account #108) when assets are retired from plant in service. Additionally, the decommissioning costs would be applied to the steam plant depreciation reserve (account #108) as they are incurred. Any unrecovered balances remaining in that reserve are recovered through the depreciation expense on the remaining steam plants.

<u>CONCLUSION</u>

Q. Does this conclude your direct testimony?

A. Yes.

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 Approval of an Integrated Resource Plan	)	Case No. U-21090
under MCL 460.6t, certain accounting	)	
approvals, and for other relief.	)	
______________________________________	)	

DIRECT TESTIMONY

OF

SRIKANTH MADDIPATI

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

Q. Please state your name and business address.

A. My name is Srikanth Maddipati, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Treasurer and Vice President of Finance and Investor Relations.

Q. What are your current responsibilities?

A. I am responsible for managing corporate liquidity, financing, and treasury operations, and maintaining relationships with the banking community, rating agencies, investors, and research analysts. As a part of my role, I am responsible for raising the financial capital required by the Company including revolving credit facilities, short and long-term debt capital, and equity capital. In order to carry out my responsibilities, I maintain constant interaction with commercial banks, investment banks, credit rating agencies, equity and fixed income analysts, as well as equity and fixed income investors. I also play a key role in the Company's strategic planning process and in developing the Company's financial plan that fulfills its strategic goals.

Q. What is your educational background?

A. I received a Bachelor of Science Degree in Computer Engineering from the University of Michigan in 2004 and, concurrently, completed my Master of Science Degree in Engineering with a specialization in Signal Processing. I received a Master of Business Administration Degree ("MBA") from the Ross School of Business at the University of Michigan in 2008, where I focused on Finance and Accounting.

Q. What positions did you hold prior to your present position?

A. I began my career in 2004 as an engineer in the Advanced Information Systems Division of General Dynamics where I developed quantitative models for a number of Department of Defense related programs. After receiving my MBA in 2008, I joined Goldman Sachs in New York as an Associate in the Financial Institutions Group. In this role, I developed financial models to value both public and private companies and executed financing transactions for companies across a number of markets including equity, investment grade and high yield debt, preferred equity, and syndicated bank loans. I developed cost of capital analyses, financing and liquidity plans, and strategic alternatives for corporate boards, management teams, and investors during a time of extreme uncertainty and financial stress in the United States and global markets (2008 and 2009). In 2011, I joined the Private Equity Group in Goldman Sachs' Asset Management Division and was promoted to Vice President in 2012. As part of this group, I analyzed and recommended investments in a wide variety of industries and assets including power and energy assets. As part of my investment recommendations, I analyzed the capital structure and required rates of return for securities across the entire capital structure (equity, debt, and hybrid). In 2014, I joined CMS Energy Corporation ("CMS Energy") and Consumers Energy as Assistant Treasurer, and I was promoted to Treasurer in 2016.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I have provided testimony on cost of capital in several cases including Case Nos. U-20650, U-20322, U20134, U-18424, U-18322, and U-18124. I have also provided testimony in the Company's first Integrated Resource Plan ("IRP"), Case No. U-20165, on the Company's proposed financial compensation mechanism. In addition, I have provided support to Dhenuvakonda Rao, who served as the Company's witness covering capital structure and cost of capital in several past electric and gas rate cases before the Commission including Case Nos. U-17990 and U-17882.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to present a methodology for establishing a financial mechanism to incentivize the use of Power Purchase Agreements ("PPAs") as well as to discuss the impact of using securitization to recover the remaining net book value of over $1.5 billion associated with the early retirement of the Company's remaining coal generating units ("the retirement units") as outlined by Company witness Jason R. Coker.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I'm sponsoring the following exhibit:

Exhibit A-34 (SM-1)	Illustration of PPA Financial Incentive; and
Exhibit A-35 (SM-2)	Impact of Securitization on Capital Structure.

Q. Was this exhibit prepared by you or at your direction?

A. Yes.

<u>PPA FINANCIAL INCENTIVE</u>

Q. Is the Commission authorized to compensate the utility for entering a PPA?

A. Yes. Public Act ("PA") 341 explicitly authorizes the Commission to approve financial incentives for the utility when entering PPAs.

Q. Please discuss the current financial incentive for PPAs.

A. In the Company's previously filed IRP, Case No. U-20165, the Commission approved a settlement agreement that authorized a financial incentive equal to the product of PPA payments made and 5.88% (the Company's after-tax weighted average cost of capital ("WACC") on its total capital structure at the time of the approved settlement).

Q. Please discuss the financial impact of PPAs.

A. PPAs are agreements that contractually obligate Consumers Energy to purchase energy and capacity from a generation provider at a pre-determined price. These long-term agreements have similar financial characteristics as long-term debt, and they can be referred to as "off-balance sheet" financings since they are not recorded on the Company's balance sheet. However, financial analysts including rating agencies will incorporate PPA obligations in their analysis since the fixed payments, similar to interest payments, reduce financial flexibility and increase the risk of default for the utility. When the PPA obligations are incorporated by financial analysts, it is often referred to as "imputed" debt. The presence of PPAs increase the necessary financial support from equity capital and the resulting impacts of the PPA imputed debt on the credit of a utility. This increased financial burden and the associated credit costs are borne by customers and investors of the Company and unless addressed, unfairly shifts costs from the PPA provider to these stakeholders.

Q. Would a PPA be possible without associated equity capital from Consumers Energy?

A. No. If the Company had not raised the associated equity capital, the Company's credit would not be sufficient to support the long-term obligations imposed by a PPA. This is hardly surprising, as PPA providers leverage the creditworthiness of PPA off-takers in order to secure advantaged financing terms, and a PPA provider would not be able to raise capital on such favorable terms, if at all, without relying on the inherent creditworthiness of Consumers Energy's – credit which is reliant on equity capital support. PPAs utilize the equity capital of the Company, and a proper compensation mechanism is essential to ensure a fair rate of return. While PPAs have the potential to add value to customers, without the associated equity capital provided by investors, the realization of these benefits would not be possible.

Q. Do PPAs have an impact on the Company's ability to attract capital?

A. Yes. The construction of generation assets requires capital whether the assets are built and owned by a utility or constructed by an Independent Power Producer ("IPP"). To the extent the assets are owned by the utility, the Company raises debt and equity in order to directly fund the investment. In contrast, for assets operated under a PPA, while the debt may not be raised directly by the utility as discussed above, the financial and creditworthiness of the utility support the associated capital financings. A PPA provider obtains the financing and associated capital necessary by using the equity capital of the utility as support. An appropriate analogy is a child obtaining a loan with their parent as a co-signer - the child receives more favorable loan terms with little or no money down because the lender is relying upon the parent's credit score and net worth to determine the favorable terms. Similarly, a PPA provider is able to utilize less equity and receive favorable debt terms because the lender is relying upon the utility's creditworthiness and equity. As a result, this PPA reliance negatively impacts the Company's ability to attract capital, and the responsibility of maintaining financial and credit metrics ultimately remains with the utility.

Q. Does the current PPA financial incentive fully address the financial impact of PPAs?

A. No. In Case No. U-20165 some intervenors, including MPSC Staff ("Staff")[1], were opposed to calculating compensation for PPAs based upon imputed debt. Instead, Staff and other intervenors[2] supported an incentive that would encourage the use of PPAs but believed the financial impacts of PPAs should be considered in a general rate case. The settlement agreement reached by the parties in that case included an incentive for PPAs, but it explicitly did not prohibit the Commission from considering the impacts of imputed debt in future cases.

Q. Please discuss the financial incentive you are proposing in this case.

A. While I believe that an appropriate PPA incentive should incorporate the impacts of imputed debt on the Company's balance sheet, I recognize that parties to this case may continue to oppose calculating a PPA incentive in such a manner. Therefore, I am proposing a PPA incentive that is simply equal to the product of: (1) the annual PPA payment; and (2) the Company's pre-tax WACC based on its permanent capital structure (currently 8.64%). This PPA incentive, in conjunction with the competitive procurement process outlined by Company witness Keith G. Troyer, would provide a reasonable alternative to using imputed debt as the basis of a PPA incentive.

Q. Why are you excluding deferred income taxes in the calculation of WACC?

A. The weighted-average cost of capital for a company is the rate of return required by investors for the deployment of capital. The Company predominantly uses two forms of capital to fund its assets, debt and equity. Given the differences in risk between debt and

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[1] MPSC Staff witness Robert F. Nichols' Direct Testimony, page 19, and MPSC Staff witness Paul Proudfoot's Direct Testimony, page 24.
[2] Most notably Michigan Environmental Council witness Douglas Jester's direct testimony, page 29.

equity, investors typically require higher rates of return for equity relative to debt. The weighted average cost of capital for the Company is derived by taking cost rates for both debt and equity weighted by the relative portion of each in the capital structure. PPA expenses would not generate any substantial deferred taxes for Consumers Energy, and therefore it is appropriate to use the pre-tax WACC of the Company's permanent capital structure to calculate the incentive.

Q. Why are you using pre-tax WACC?

A. Any incentive earned by the Company for entering PPAs would be subject to income tax and therefore the appropriate incentive should clearly be based on pre-tax WACC.

Q. Does the outlined compensation mechanism meet the requirements of PA 341?

A. Yes. PA 341 states the following:

> For power purchase agreements that a utility enters into after the effective date of the amendatory act that added this section with an entity that is not affiliated with that utility, the commission shall consider and may authorize a financial incentive for that utility that does not exceed the utility's weighted average cost of capital.

My proposed incentive mechanism uses the weighted average cost of capital to directly calculate the incentive amount. While I believe the statute would allow for the Company to earn based on the entire imputed debt created by a PPA, my proposal only applies to an annual PPA payment.

Q. Please discuss how a PPA incentive helps customers.

A. A PPA incentive helps align the Company's and customer interests by removing potential bias towards utility-owned assets. This alignment of interests allows customers to access potentially lower cost supply alternatives while providing a fair return. As noted by Staff in Case No. U-20165, given the utility revenue model is contingent on owned assets, absent a meaningful incentive, entering PPAs for a significant portion of the Company's capacity needs is not a realistic expectation:

> However, without a PPA incentive that is high enough for the Company to accept, it may be difficult to expect the Company to enter into thousands of megawatts of PPAs for solar resources if they have a low incentive with little opportunity to earn on those PPAs. [Direct testimony of Staff witness Paul Proudfoot, MPSC Case No. U-20165, page 31.]

RECOVERY METHODOLOGY OF UNRECOVERED BOOK BALANCES

Q. How does the Company propose recovering the remaining book balances of the proposed retirement units?

A. The Company's proposed method of recovery for the remaining book balances is outlined by Company witness Coker. The Company is proposing to recover the remaining net book value of the assets by moving the balances to a regulatory asset and recovering this asset through traditional ratemaking over the currently planned remaining life of the units.

Q. Why is the Company not proposing to recover the remaining net book value by the proposed retirement dates?

A. There is substantial net book value remaining in the proposed retirement units, in particular J.H. Campbell ("Campbell") Unit 3. Recovery of these balances by 2025 would create a significant burden on customers in the form of increased customer rates due to much higher depreciation expense. Recovery of the net book value over the remaining design life is consistent with the recovery currently in customer rates and balances the rate impacts of current customers with those of future customers.

In the Company's 2018 IRP, several intervenors proposed that the Company not be allowed to earn a return on the unrecovered book balances after the plants were retired. As discussed by Company witness Coker, if the Commission does not authorize a method of recovering the remaining net book value of the plants including full recovery of financing costs at the same time the PCA is approved, the Company would be required to write off a portion of the net book value of D.E. Karn ("Karn") Units 3 and 4 and Campbell Units 1, 2, and 3 and record an impairment for accounting purposes. Such an outcome is not reasonable or prudent. The investments in these plants were reasonable at the time they were made and approved by the Commission in numerous rate case orders over the span of many years. Changed circumstances do not render those investments unreasonable merely because parties to this case may prefer to reevaluate the original investment through the lens of perfect hindsight. The reasonableness of an investment, and by extension, its appropriateness for recovery through rates, should always be considered on the basis of what was known at the time the investment decisions were made.

Q. How have other jurisdictions addressed the recovery of remaining book value associated with the early retirement of generating units?

A. There does not appear to be any universal approach to the recovery of generation facilities that are retired early. However, several jurisdictions that have recently dealt with the early retirement of generating units have recognized the need to ensure the means of recovery for the utility, including earning a return on the remaining value until recovery is complete. Some examples that I am aware of outside of Michigan include the following:

- In Florida, Florida Power and Light has had several examples of coal units retired early that are being recovered as regulatory assets over varying lengths (9 to 15 years);
    - Cedar Bay coal generation facility regulatory asset amortized over ~10-year period;
    - Indiantown coal generation facility regulatory asset amortized over an ~9-year period; and

  - St. Johns River coal generation facility regulatory asset amortized over a 10-year period once base rates reset in a general base rate case.

- In Colorado, Public Service Company of Colorado recovered the early retirement of its Comanche 1 & 2 coal units through accelerated depreciation; and

- In Wisconsin, both Wisconsin Electric Power Company and Wisconsin Power and Light Company provide examples.

  - Wisconsin Electric Power Company ("WEPCo") has over $800 million of unrecovered book value associated with plant retirements. These include unrecovered book value for the Pleasant Prairie power plant, Pulliam Units 7 and 8, and the Edgewater 4 generating units which were all retired in 2018. The Wisconsin Public Service Commission authorized approval to collect a return of and on the entire net book value of the retired generating units.

  - Wisconsin Power and Light Company filed an application for approval of settlement agreement on May 27, 2021. The settlement agreement would allow the company to recover its unrecovered book value in the Edgewater Unit 5 facility through a regulatory asset amortizing over ~25 years. While the settlement agreement has not yet received final approval from the Wisconsin Public Service Commission, approval of such a comprehensive settlement agreement seems to be likely.

Q. Should the Commission consider any form of base rate recovery of the investments in the retirement units that does not include a return on the investment?

A. No. Such an approach would result in an impairment and a write off, which would have serious detrimental impacts.

Q. Discuss the impact of financing an early retirement without a return.

A. Utilities make investment in long-term assets that can take decades to recover. Investments that have long time horizons often require higher returns as macroeconomic factors, technology, and legislation can change over time. The stability provided by Michigan's regulatory environment allows the Company to secure lower cost long-term financing and encourages investments that improve safety, reliability, and affordability. One of the key criteria used by rating agencies is the quality of a utility's regulatory environment and as noted by both Moody's and S&P, the recovery of investments and the ability to earn a reasonable return are key components of that analysis:

> A utility operating in a regulatory framework that, by statute or practice, allows the regulator to arbitrarily prevent the utility from recovering its costs or earning a reasonable return on prudently incurred investments, or where regulatory decisions may be reversed by politicians seeking to enhance their populist appeal will receive a much lower score. [Moody's June 23, 2017 Regulated Electric and Gas Utilities Rating Methodology Report, page 7.]

> The utility can fully and timely recover all its fixed and variable operating costs, investments and capital costs (depreciation and a reasonable return on the asset base). [S&P's November 19, 2013 Key Credit Factors for the Regulated Utilities Industry Report, page 7.]

To the extent the Company is forced to take an impairment on investments that were previously deemed reasonable and prudent, such an action would raise serious questions regarding the stability of Michigan's regulatory environment and ultimately negatively impact or raise the Company's long-term financing costs, thereby discouraging future investments.

Furthermore, it would encourage recovery of assets over shorter timeframes in order to avoid the uncertainty of regulatory outcomes. For example, the remaining unrecovered net book value for the proposed retirement units is approximately $1.5 billion at December 31, 2022. Accelerated recovery of this remaining amount between 2023 and 2025 would require nearly $517 million per year. Such an action would drive large increases in customer rates. In contrast, allowing assets to be financed over longer periods of time provides a more balanced approach for customers.

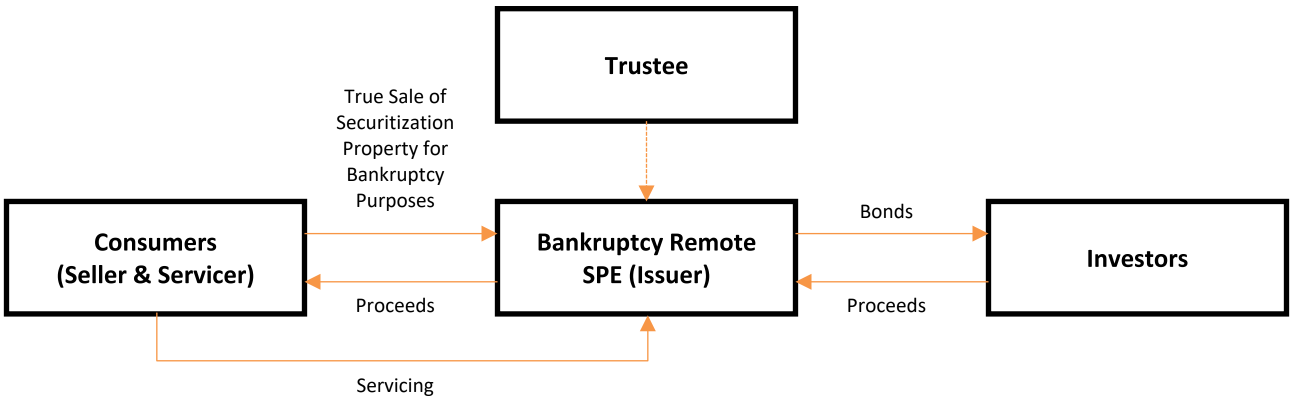
Q. Please discuss securitization and the role it has played in Consumers Energy's other recent early retirements of generating units.

A. Securitization is the financing method in which a discrete asset or group of assets, (e.g. storm costs, unrecovered net book value), are separated from the utility and financed with securities whose credit quality is separated from that of the utility in order to achieve higher credit ratings and lower financing costs. In order to accomplish this, the utility sells the revenue stream and other entitlements and property created by the financing order to a newly established bankruptcy remote special purpose entity ("SPE" or "Issuer") in a transaction which represents a "true sale" for bankruptcy purposes. This sale insulates the securitization property from the creditors of the utility and, thereby, from the credit risk of the utility. The SPE then issues bonds backed by the securitization property and "other collateral" to investors/bondholders. A trustee acts on behalf of bondholders, remits payments to bondholders and ensures bondholders' rights are protected in accordance with the terms of the financing documents. The company performs routine billing, collection, and reporting duties as the servicer for the Issuer pursuant to a servicing agreement between the company, the Issuer and the trustee. In addition to the bankruptcy remote status of the Issuer, credit enhancements, such as a capital contribution to the Issuer and a true-up mechanism, are necessary to reach the rating standard for this type of securitization, which is the highest rating (a "triple-A rating") from each of two or more of the major rating agencies.

Consumers Energy used securitization financing to recovery the remaining book values for its "Classic 7" generating plants retired in early 2016 and has been approved by the Commission to recover the remaining book value for the early retirement of Karn Units

1 and 2, which are planned for retirement in 2023 as an outcome of the Company's 2018 IRP in Case No. U-20165. Diagram 1, which is representative of a securitization transaction, follows.

Diagram 1



Q. What is the history of securitization financing?

A. Securitization as a vehicle for financing was initially established as states deregulated their energy markets. The majority of securitizations of which I am aware were utilized to fund stranded costs related to formerly vertically integrated utilities divesting their generation assets. In Michigan, securitization financing was established in 2000 through PA 142 in order to facilitate deregulation of the State's energy markets. However, since 2000 the state has returned to the regulation of electric generation in 2008 via PA 286.

Q. Please discuss the impacts of securitization.

A. Similar to PPAs, a securitization creates a long-term financial obligation that has an impact on the credit of the Company. Unlike PPAs, however, securitization debt is included on the Company's balance sheet and therefore its impact on the Company's capital structure is readily observed. The most significant aspect in which a securitization negatively impacts the Company is with regard to the Company's credit rating metrics. Moody's includes securitization debt as part of the capital structure of the company and includes the securitized debt in the corporate rating analysis despite being considered non-recourse debt. This inclusion of securitization debt adversely impacts the Company's corporate rating. Specifically, Moody's stated in their *Corporate Methodology for Electric and Gas Utilities* from June 23, 2017:

> In general, we view securitization debt of utilities as being on-credit debt, in part because the ratings associated with it reduce the utility's headroom to increase rates for other purposes while keeping all-in company's ratios by including the securitization debt and related revenues for our analysis. Where the securitized debt is on balance sheet, our credit analysis also considers the significance of ratios that exclude securitization debt and related revenues. Since securitization debt amortizes mortgage-style, including it makes ratios look worse in early years (when most of the revenue collected goes to pay interest) and better in later years (when most of the revenue collected goes to pay principal)." (Emphasis Added). [Moody's, June 23, 2017.]

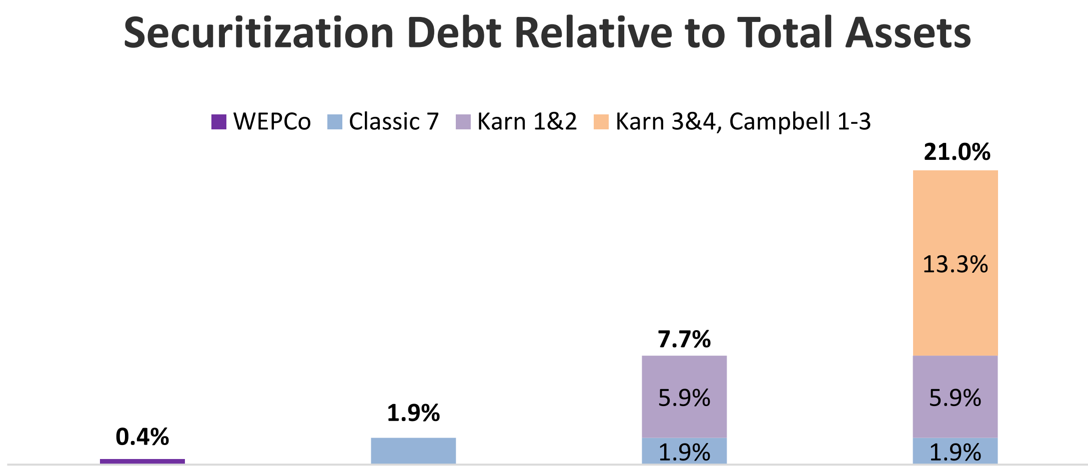
Moody's methodology explanation makes it very clear that securitizations are neither positive nor neutral, but in fact, negative for a company's credit ratings.

Q. Please discuss the use of securitization proceeds.

A. Historically, the Company has used the proceeds from securitization to pay down debt and equity in equal portions. While that may have been reasonable when the balance of securitization debt was relatively modest (such that the capital structure remained balanced when including securitization) as in the case of the Classic 7 securitization, the magnitude of incremental securitization debt that additional securitization financings would place on the Company's balance sheet skews the relative balance of debt and equity. Exhibit A-35 (SM-2), provides an illustration of this impact using the Company's most recently approved capital structure and demonstrates that doing so would skew the balance toward using more debt than equity (see column (h)). I am aware of only one utility that has issued securitization bonds to retire coal plants, which was WEPCo's Pleasant Prairie power plant. However, in that case, only approximately $100 million of the $600 million of unrecovered book value was securitized. The remaining approximately $500 million was recovered through 2039 with a return of and on the remaining balances.

Q. Is securitization the preferred method of recovering the undepreciated balances associated with the potential early retirement of the Company's remaining coal plants as proposed in this case?

A. No. In fact, it appears that the issuance of securitization bonds for early coal retirements is much less common than allowing the assets to be recovered through a regulatory asset with a return of and on unrecovered balances. Due to the securitizations approved for the Classic 7 plants and for Karn Units 1 & 2, Consumers Energy will already have a substantial amount of securitization debt reflected on its Generally Accepted Accounting Principles ("GAAP") accounting statements. In comparison to WEPCo which issued $100 million of securitization bonds, the percentage of securitization debt relative to total assets is dramatically higher.



Source: WEPCo data depicts $100M securitization as percentage of total WEC Energy PP&E per company 2020 10-K. Classic 7 securitization balance as of Company 2020 10-K. Karn 1&2 securitization amount per Case No. U-20889 Order. Karn 3&4, Campbell 1-3 balance as of December 31, 2022, per Exhibit KJW-1. Company approved rate base in Case No. U-20697.

Consumers Energy submits that it is much more common and preferable to recover the undepreciated portion of the remaining coal plants through the more traditional cost recovery methods described above.

Q. Please discuss how the impact of securitization could be addressed if used as the method of recovery.

A. Because securitization debt is recorded on the GAAP balance sheet of the Company, the Commission could accommodate the impact of securitization by considering the incorporation of securitization debt in determining a balanced capital structure. Doing so would ensure the amount of equity used in determining regulatory capital would be relative to debt including securitization debt. Exhibit A-35 (SM-2) column (j), shows how a proposed rebalanced capital structure would be determined using the Commission's stated desire to have the Company at 50/50 debt and equity capital structure. The need for rebalancing and the impact of securitization debt would decline as the securitization debt amortizes over the tenor of the bonds.

Q. How would the method of recovery impact the Company's PCA?

A. The Company would not be able to proceed with the PCA unless the Company is able to recover the unrecovered net book balances in a manner that preserves both the Company's credit and financial profile.

Any recovery mechanism that resulted in the Company incurring an impairment or financing assets over a long period of time without proper compensation for the capital needed to finance those assets would not be a prudent course of action. Increasing the Company's leverage through the use of securitization would limit the financial flexibility of the Company and hinder the Company's ability to make necessary capital investments proposed in the PCA (the purchase of existing gas units and deployment of solar) as well to make investments to improve our electric distribution infrastructure more broadly.

The Company's proposal to recover the remaining book balances of the retirement units over their remaining design life is a balanced proposal that would preserve the company's credit and financial profile and is a requirement for the Company to proceed with the PCA as proposed.

Q. Does this complete your direct testimony?

A. Yes.

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 Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))))	Case No. U-21090

DIRECT TESTIMONY

OF

JASON R. COKER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

Q. Please state your name and business address.

A. My name is Jason R. Coker, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Principal Rate Analyst in the Revenue Requirements and Analysis Section of the Rates and Regulation Department.

Q. Please describe your educational background.

A. I graduated from Western Michigan University in 1999 with a Bachelor of Business Administration Degree, majoring in Accounting. I am also a Certified Public Accountant registered in the state of Michigan.

Q. Please describe your professional experience.

A. From 1999 to 2003, I was employed by Willis and Jurasek, PC in Jackson, Michigan as a staff auditor working on financial audits and income tax returns. In 2003, I became the Director of Accounting for Delhi Charter Township in Holt, Michigan. In that role, I had overall responsibility for the Township's payroll, accounts payable, accounting, financial reporting, and budgeting. In 2005, I joined Consumers Energy as a General Accounting Analyst II in the Technical Accounting and Accounting Policy Department. My responsibilities included the implementation of new financial accounting standards, research of technical accounting issues, and review of contracts for accounting issues. In 2009, I was promoted to Senior Accounting Analyst and assumed responsibility for restricted stock accounting and some Securities and Exchange Commission reporting disclosures while maintaining my previous duties. In 2012, I assumed responsibility for accounting and reporting of contingencies, including Consumers Energy's manufactured gas plants. In 2016, I accepted the position of Senior Rate Analyst II in the Revenue Requirement Section of the Rates and Regulation Department. I was promoted to Principal Rate Analyst in 2018.

Q. What are your responsibilities as a Principal Rate Analyst in the Revenue Requirements and Analysis Section at Consumers Energy?

A. As a Principal Rate Analyst, I am responsible for calculating the Gas Cost Recovery ("GCR") factor on a monthly basis. I am also responsible for developing, analyzing, and reviewing the Company's monthly return studies. These include studies pertaining to balance sheet working capital, cost of capital, return on investment, and Return on Equity ("ROE"). In addition, I assist in the development of analyses related to the Company's revenue requirements and the preparation of electric and gas rate case filings at the Michigan Public Service Commission ("MPSC" or the "Commission"). I am also responsible for various ad hoc studies pertaining to cost of capital, ROE, and revenue requirements.

Q. Have you previously provided testimony before the Commission on behalf of the Company?

A. Yes.

Q. Please state the proceedings in which you have been involved.

A. I have provided testimony in the following cases:

- Electric General Rate Case Nos. U-18322 and U-20963;
- Gas General Rate Case Nos. U-18424, U-20322, and U-20650;
- Saginaw Trail Pipeline Act 9 Filing Case No. U-18166;

- GCR Reconciliation Case Nos. U-17943-R, U-20075, U-20209, and U-20234; and
- GCR Plan Case Nos. U-18411, and U-20233.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to support the fixed charge rate used in the Integrated Resource Plan ("IRP") modeling. My direct testimony also provides rate impacts for the Proposed Course of Action ("PCA"). In addition, my direct testimony presents proposed treatment and recovery of the remaining unrecovered net book value of D.E. Karn ("Karn") Units 3 and 4 and J.H. Campbell ("Campbell") Units 1, 2, and 3. Finally, my direct testimony presents proposed treatment of costs associated with community transition plans for the Karn and Campbell sites and expenses associated with the Campbell retention and separation plan.

Q. How is the remainder of your direct testimony organized?

A. My direct testimony is organized into four sections. Section I supports the fixed charge rate used in the IRP modeling, Section II discusses rate impacts, Section III presents proposed treatment and recovery of the remaining net book value of Karn Units 3 and 4 and Campbell Units 1, 2, and 3; and Section IV presents proposed treatment and recovery of the Campbell Retention and Separation Benefits and the Community Transition Plan.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-36 (JRC-1)	Incremental Revenue Requirement – Proposed Course of Action;
Exhibit A-37 (JRC-2)	Net Book Value Recovery;
Exhibit A-38 (JRC-3)	Incremental Revenue Requirement – Other Scenarios;

Exhibit A-39 (JRC-4)	Revenue Requirement – Covert; and
Exhibit A-40 (JRC-5)	Revenue Requirement – DIG, Kalamazoo, and Livingston plants.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

<u>SECTION I: FIXED CHARGE RATE</u>

Q. What is the fixed charge rate?

A. The fixed charge rate provides the amount-per-dollar of original investment outlay which an investment must generate each and every year over the course of its anticipated average service life in order to meet a specified annual rate of return given a set of assumptions regarding cost of removal, state income tax, federal income tax, and tax life. In addition, the net average Company property tax and insurance annual rates are used in the computation.

Q. Was the fixed charge rate used in the IRP Modeling?

A. Yes. As explained by Company witness Sara T. Walz, the fixed charge rate was one of the assumptions used by her in the IRP modeling.

<u>SECTION II: RATE IMPACTS</u>

Q. Please describe Exhibit A-36 (JRC-1).

A. Exhibit A-36 (JRC-1) provides an analysis of the rate impacts for the PCA. Line 1 provides the incremental revenue requirement for the PCA. Lines 2 and 3 provide percentage change in revenue requirement and the year-over-year percentage change in revenue requirement. Lines 4 and 5 provide cents per kWh changes and year-over-year cents per kWh changes. Line 6 provides the net present value of the incremental revenue requirements through 2040.

Q. Overall, what does Exhibit A-36 (JRC-1) demonstrate?

A. Exhibit A-36 (JRC-1) shows that the PCA provides a net present value decrease in the incremental revenue requirement of $290,015,000 through 2040. The incremental annual revenue requirement is negative in 19 of 21 years.

Q. Please explain what the incremental revenue requirement represents as presented on line 1 of Exhibit A-36 (JRC-1).

A. The incremental revenue requirement on line 1 of Exhibit A-36 (JRC-1) represents the difference in revenue requirement between the Alternate Plan and the PCA. Company witness Richard T. Blumenstock discusses the PCA and the Alternate Plan in his direct testimony. The incremental revenue requirement is calculated by summing the change in return on rate base, depreciation expense, and property tax caused by differences in capital spending between the Alternate Plan and the PCA. The difference in Operation and Maintenance ("O&M") expense and change in Power Supply Cost Recovery ("PSCR") costs is then added to the sum of the capital spend impacts for the total incremental revenue requirement. Company witness Walz provides the incremental capital spending, O&M expense, property tax expense, and PSCR expense used in the calculation of the incremental revenue requirement.

Q. Does the incremental revenue requirement as presented on Exhibit A-36 (JRC-1), line 1, include all expected changes in revenue requirement through 2040?

A. No. The incremental revenue requirement as presented on Exhibit A-36 (JRC-1), line 1, does not include all expected changes in revenue requirement through 2040. The incremental revenue requirement is limited to the change in revenue requirement when comparing the Alternate Plan scenario to the PCA. There are many other items that are likely to impact the revenue requirement through the year 2040. For example, this does not consider the expected decline in rate base from the depreciation of other generation assets that would cause a reduction in revenue requirement. The revenue requirement calculation also excludes any changes in distribution system revenue requirements. Thus, the incremental revenue requirement, as presented, is intended only to isolate the difference in revenue requirement from the Alternate Plan scenario and the PCA.

Q. Does the incremental revenue requirement for the PCA as presented on Exhibit A-36 (JRC-1), line 1, include the revenue requirement impacts of collecting the remaining net book value of Karn Units 3 and 4 and Campbell Units 1, 2, and 3?

A. No. Exhibit A-36 (JRC-1), line 1, does not include the revenue requirement impacts of collecting the remaining net book value of Karn Units 3 and 4 and Campbell Units 1, 2, and 3. The PCA, outlined as part of this filing, does not alter the need to recover the remaining net book value of Karn Units 3 and 4 and Campbell Units 1, 2, and 3. The Company has not yet recovered the asset value of Karn Units 3 and 4 and Campbell Units 1, 2, and 3 and would need to do so regardless of the selected retirement date of these units. The remaining net book value of these units represent dollars spent by the Company not yet recovered through rates. Section III provides an analysis and recommendation for the treatment and collection of this remaining net book value.

Q. What rate of return was used in the incremental revenue requirement calculation?

A. A pretax rate of return of 7.40% was used in calculating the incremental revenue requirement. This pretax rate of return represents the approved pretax rate of return from Case No. U-20134, which was the Company's most recent electric rate order that was available during development of the PCA.

Q. Exhibit A-36 (JRC-1), line 2, provides a percentage change in revenue requirement. Please explain how that is calculated.

A. The percentage change in revenue requirements divides each year's incremental revenue requirement by the base rate and PSCR revenue requirement from Case No. U-20134, adjusted to incorporate the revenue requirement associated with the currently billed Energy Waste Reduction ("EWR") surcharge.

Q. Please explain Exhibit A-36 (JRC-1), lines 4 through 6.

A. Exhibit A-36 (JRC-1), lines 4 and 5, provide the cents/kWh impacts of the incremental revenue requirement. Line 4 shows the total cents/kWh impact calculated by dividing the incremental revenue requirement for each year by the full-service kWh from Case No. U-20134. Exhibit A-36 (JRC-1), line 6, provides the net present value of the incremental revenue requirements of the PCA.

Q. What discount rate was used in this calculation?

A. The net present value calculation on line 8 uses a discount rate of 7.40% representing the pretax rate of return approved in the most recent electric rate available during development of the PCA.

Q. Does the PCA, outlined as part of this filing, cause the need to recover the remaining net book value of Karn Units 3 and 4 and Campbell Units 1, 2, and 3?

A. No. The Company has not yet recovered the asset value of Karn Units 3 and 4 and Campbell Units 1, 2, and 3 and would need to do so regardless of the selected retirement date of these units. The remaining net book value represent dollars spent by the Company not yet recovered through rates.

Q. Please describe Exhibit A-38 (JRC-3).

A. Exhibit A-38 (JRC-3) provides rate impact analysis for the other retirement scenarios the Company analyzed as labeled on the exhibit. The calculations included in this analysis follow the same methodology as described for the PCA above.

Q. Please describe Exhibit A-39 (JRC-4).

A. Exhibit A-39 (JRC-4) provides the revenue requirement calculation of the to-be-purchased Covert Plant. Line 1 shows the projected capital spending, as discussed by Company witness Norman J. Kapala. Line 2 shows the average rate base, which is the net of the calculated average plant-in-service and the calculated average depreciation reserve. Line 4 is the calculated return on the plant's projected rate base, derived by multiplying line 2 by line 3. Line 5 provides the projected depreciation expense. Line 6 provides the O&M and Property taxes, sponsored by Company witness Kapala. Line 7 is the sum of lines 4 through 6 and provides the total projected revenue requirement for the Covert plant.

Q. Please describe Exhibit A-40 (JRC-5).

A. Exhibit A-40 (JRC-5) provides the revenue requirement calculation of the to-be-purchased DIG, Kalamazoo, and Livingston plants. The calculations included in this analysis follow the same methodology as described for Exhibit A-39 (JRC-4) above.

Q. What approvals are required from the Commission regarding the purchase cost of the Covert and DIG, Kalamazoo, and Livingston plants?

A. The Company requests that the Commission approve recovery of the full purchase cost of the plants inclusive of acquisition costs and any acquisition adjustment. An acquisition adjustment represents the difference between the cost of the acquired plant and the original cost of the acquired plant less the provision for accumulated depreciation. Recovery of the acquisition adjustment is required in order to recover the full costs of acquiring the plant.

Q. Has the Commission approved recovery of an acquisition adjustment previously?

A. Yes. The Commission approved recovery of the acquisition adjustment related to the purchase of the Zeeland Plant in Case No. U-15245.

SECTION III: NET BOOK VALUE

Q. Under the PCA, when will Karn Units 3 and 4 retire?

A. Under the PCA, Karn Units 3 and 4 will retire in 2023.

Q. What is the estimated remaining unrecovered net book value of Karn units 3 and 4 at the beginning of 2023?

A. As provided by Company witness Kevin J. Watkins, the estimated remaining net book value of Karn Units 3 and 4 at the beginning of 2023 is $111,996,000.

Q. What are the estimated decommissioning costs for Karn Units 3 and 4 with a 2023 retirement date?

A. As provided by Company witness Watkins, the estimated decommissioning costs for Karn Units 3 and 4 is $29,486,000.

Q. Under the PCA, when will Campbell Units 1 and 2 retire?

A. Under the PCA, Campbell Units 1 and 2 will retire in 2025.

Q. What is the estimated remaining unrecovered net book value of Campbell Units 1 and 2 at the beginning of 2023?

A. As provided by Company witness Watkins, the estimated remaining net book value of Campbell Units 1 and 2 at the beginning of 2023 is $513,884,000.

Q. What are the estimated decommissioning costs for Campbell Units 1 and 2 with a 2025 retirement date?

A. As provided by Company witness Watkins, the estimated decommissioning costs for Campbell Units 1 and 2 is $68,033,000.

Q. Under the PCA, when will Campbell Unit 3 retire?

A. Under the PCA, Campbell Unit 3 will retire in 2025.

Q. What is the estimated remaining unrecovered net book value of Campbell Unit 3 at the beginning of 2023?

A. As provided by Company witness Watkins, the estimated remaining net book value of Campbell Unit 3 at the beginning of 2023 is $923,811,000.

Q. What are the estimated decommissioning costs for Campbell Unit 3 with a 2025 retirement date?

A. As provided by Company witness Watkins, the estimated decommissioning costs for Campbell Unit 3 is $76,953,000.

Q. How does the Company propose to recover the remaining net book value and decommissioning of Karn Units 3 and 4 and Campbell Units 1, 2, and 3?

A. The Company proposes to continue to depreciate Karn Units 3 and 4 and Campbell Units 1, 2, and 3 at the current Commission-approved depreciation rates until base rates are reset in the next electric general rate case. In the next rate case filed after the conclusion of this case, the actual remaining net book value would be removed from plant-in-service and accumulated depreciation accounts and placed into a regulatory asset. The Company proposes that the Commission set an annual amortization rate that allows for the recovery of the remaining net book value and the decommissioning costs through May 2031 for costs associated with Karn Units 3 and 4 and Campbell Units 1 and 2 and through May 2040 for costs associated with Campbell Unit 3.

Q. How will this proposal impact the next electric depreciation case filed by the Company?

A. The next electric depreciation case should remove Karn Units 3 and 4 and Campbell Units 1, 2, and 3 from the analysis to reflect the fact that those assets will be, or already were, moved to a regulatory asset.

Q. Does the Company propose to make any adjustments to the regulatory asset after it is established?

A. Yes. The Company proposes that any capital expenditures for Karn Units 3 and 4 and Campbell Units 1, 2, and 3 made after the establishment of the regulatory asset should be recorded to the regulatory asset. In addition, the Company proposes to increase the regulatory asset for decommissioning dollars spent.

Q. Why does the Company propose to increase the regulatory asset for decommissioning dollars spent?

A. The amortization of the regulatory asset will include amounts sufficient to collect for decommissioning. However, the regulatory asset balance will not include an amount for decommissioning. Once decommissioning costs are incurred, they need to be recorded as an increase to the regulatory asset to offset the decreases caused by the decommissioning piece of the amortization.

Q. Under this proposal, would the Company earn a return on decommissioning prior to it being spent?

A. No. Decommissioning costs would not be recorded to the regulatory asset until actually spent and would not receive a return until recorded to the regulatory asset and only on the amounts spent that is not offset by amounts collected through the amortization. The amortization established to recover the remaining book value and decommissioning costs acts to lower the regulatory assets balance and acts as an offset for any decommissioning costs recorded in the regulatory asset.

Q. Please describe Exhibit A-37 (JRC-2).

A. Exhibit A-37 (JRC-2) provides the revenue requirement of recovering the remaining net book value of Karn Units 3 and 4 and Campbell Units 1 and 2 as of the end of 2022 through a regulatory asset amortized through May 2031 and the revenue requirement of recovering the remaining net book value of Campbell Unit 3 through a regulatory asset amortized through May 2040. Lines 1 through 4 provide the revenue requirements of the remaining net book value of Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3 and the total of all the units for each year through 2040. Lines 5 through 7 provide the change in revenue requirements of the remaining net book value of Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3 compared to their respective 2019 revenue requirements. Line 8 shows the total change in revenue requirements of the remaining net book values as compared to their 2019 revenue requirements.

Q. What does Exhibit A-37 (JRC-2) show?

A. Exhibit A-37 (JRC-2) shows that the combined revenue requirement of the recovery of the remaining net book value for Karn Units 3 and 4 and Campbell Units 1, 2, and 3 is less than the 2019 revenue requirement of the units in all years from 2023 through 2040.

Q. Please explain the regulatory asset treatment.

A. The regulatory asset treatment assumes that the remaining net book value for Karn Units 3 and 4 and Campbell Units 1, 2, and 3 will be removed from plant-in-service accounts and recorded in a regulatory asset in the next general electric rate case. The regulatory asset would be amortized to recover the remaining net book value and decommissioning costs for Karn Units 3 and 4 and Campbell Units 1 and 2 through May 2031 and would recover the remaining net book value and decommissioning costs for Campbell Unit 3 through May 2040.

Q. How did the Company choose the end of the year 2022 for the data from which to calculate the remaining unrecovered net book value?

A. The Company chose the end of the year 2022 because it represents the end of the year during which resolution of this case is expected.

Q. How did the Company determine the period over which to recover the regulatory assets?

A. The Company requests to recover the regulatory assets over each generating unit's remaining design life. This recovery period was chosen because it limits the impact on the revenue requirement while also recovering the costs over a reasonable period. Additionally, it is an objective time frame, since this represents the same period over which the remaining net book value would be recovered if the units are not retired early.

Q. Please explain why the Company is proposing the regulatory asset treatment.

A. Company witness Srikanth Maddipati describes the implications of alternate methods of recovering the remaining net book value of the plants proposed for retirement.

Q. Have other methods of recovering net book value of retired plants been used?

A. Yes. The Commission has previously authorized the Company to recover the remaining net book value of Karn Units 1 and 2 and the Classic 7 Units through securitizations.

Q. Is securitization proposed for the remaining net book values related to the coal plant retirements in this case?

A. No. Please refer to the testimony of Company witness Maddipati for discussion of securitization of the remaining net book values related to the coal plant retirements in this case.

Q. Why is it important for the Company to receive an order in this case that definitively authorizes regulatory asset treatment of the remaining net book value of Karn Units 3 and 4 and Campbell Units 1, 2, and 3?

A. Under Generally Accepted Accounting Principles ("GAAP"), the net book value of the plants must be removed from plant-in-service when it becomes probable that the plants will be abandoned before the end of their useful life. If the Commission approves the PCA in this case it would become probable that the plants will be retired and abandoned. If the Commission authorizes regulatory asset treatment with full return, a regulatory asset in the amount of the remaining net book value would be recorded for GAAP purposes and no impairment loss would be recorded. However, if the Commission does not authorize a method of recovering the remaining net book value of the plants including full recovery of financing costs, at the same time the PCA is approved, the Company would be required to write off a portion of the net book value of Karn Units 3 and 4 and Campbell Units 1, 2, and 3 and record an impairment for accounting purposes under GAAP.

SECTION IV: COMMUNITY TRANSITION COSTS AND RETENTION AND SEVERANCE COSTS

Q. Is the Company proposing special accounting treatment for community transition costs associated with the retirement of Karn Units 3 and 4 and Campbell Units 1, 2, and 3?

A. Yes. The Company proposes to defer and record a regulatory asset for costs associated with the community transition plans for the Karn site and the Campbell site. Company witness Kapala provides further details regarding the community transition plans.

Q. Please state the proposal for recovery of costs related to community transition costs for the Karn site and the Campbell site.

A. The Company requests that the Commission authorize Consumers Energy to defer expense related to the community transition plans as described by Company witness Kapala, utilizing a regulatory asset to record the deferred amounts. Recognition of amortization expense of the deferred amounts would be addressed in a future rate case.

Q. How do you propose these costs be recovered?

A. The Company proposes that these costs be deferred through the conclusion of the community transition plans. The amortization period and associated expense would be approved in a future rate case after review by the Commission. The deferred unamortized balance would be included in rate base and would earn a return at the authorized rate of return.

Q. Is the Company proposing special accounting treatment for retention and separation costs associated with the retirement of Campbell Units 1, 2, and 3?

A. Yes. Company witness Kapala discusses the retention and separation plan in detail in his testimony.

Q. Please state the proposal for recovery of costs related to the Campbell retention and separation plan.

A. The Company requests that the Commission authorize Consumers Energy to defer expense related to the Campbell severance and retention agreement, utilizing a regulatory asset to record the deferred amounts. Amortization of the deferred amounts would be addressed in a future rate case.

Q. What is the projected amount of deferred costs related to the retention separation agreement?

A. Consumers Energy estimates total O&M costs to be deferred of $60 million for the 2022 through 2025 period. Costs deferred and requested for recovery in a future rate case may be higher or lower to match actual costs incurred.

Q. How do you propose these costs be recovered?

A. The Company proposes that these costs be deferred through the closure of the plants in 2025. The amortization period and expense would be approved in future rate cases. The deferred unamortized balance would be included in rate base and would earn a return at the authorized rate of return.

Q. Why should the Commission approve the proposed regulatory asset treatment for expenses associated with community transition plans for the Karn site and the Campbell site and regulatory asset treatment for expenses associated with the Campbell retention and separation plan?

A. Expenses of the community transition plans for the Karn site and the Campbell site and expenses of the Campbell retention and separation plan have not been included in the Company's open electric rate case. These are expenses incurred to serve the Company's customers and the communities where the plants are located. Capturing these expenses in a regulatory asset will allow for future review and recovery of these costs if they are deemed to be prudent.

Q. Please summarize the relief requested from the Commission in this proceeding related to the remaining unrecovered net book value recovery of Karn Units 3 and 4 and Campbell Units 1, 2, and 3 and other costs associated with the early retirement of Karn Units 3 and 4 and Campbell Units 1, 2, and 3.

A. The Company requests that the Commission order in this case:

1. Approval to recover the full purchase cost of the to-be-purchased Covert, DIG, Kalamazoo, and Livingston plants, inclusive of any acquisition adjustments and acquisition costs;

2. Approval of regulatory asset treatment of the remaining net book value of Karn Units 3 and 4 and Campbell Units 1, 2, and 3;

3. Approval to remove Karn Units 3 and 4 and Campbell Units 1, 2, and 3 net book value from plant-in-service and accumulated depreciation accounts and record the net amount in the approved regulatory asset account in the next electric general rate case;

4. Approval to establish a regulatory asset amortization amount in the next general rate case that will allow for recovery of the remaining net book value and decommissioning costs of Karn Units 3 and 4 and Campbell Units 1 and 2 through May 2031;

5. Approval to establish a regulatory asset amortization amount in the next general rate case that will allow for recovery of the remaining net book value and decommissioning costs of Campbell Unit 3 through May 2040;

6. Approval to allow capital spending for Karn Units 3 and 4 and Campbell Units 1, 2, and 3 incurred after the establishment of the regulatory asset to be recorded in the regulatory asset and to allow decommissioning cost incurred to be recorded to the regulatory asset;

7. Approval to remove Karn Units 3 and 4 and Campbell Units 1, 2, and 3 from the analysis of the next electric depreciation case;

8. Approval of regulatory asset treatment for expenses associated with community transition plans for the Karn site and the Campbell site with the amortization period to be set in a future rate case with the unamortized balance included in rate base earning a return at the authorized rate of return; and

9. Approval of regulatory asset treatment for expenses associated the Campbell retention and separation plan with the amortization period to be set in a future rate case with the unamortized balance included in rate base earning a return at the authorized rate of return;

Q. Does this conclude your direct testimony?

A. Yes.

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 Approval of an Integrated Resource Plan	)	Case No. U-21090
under MCL 460.6t, certain accounting	)	
approvals, and for other relief.	)	
______________________________________	)	

DIRECT TESTIMONY

OF

JEFFREY E. BATTAGLIA

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

Q. Please state your name and business address.

A. My name is Jeffrey E. Battaglia. My business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

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

Q. In what capacity are you employed?

A. I am the Director of Enterprise Project Management – Generation Transformation.

QUALIFICATIONS

Q. Please describe your educational background and work experience.

A. I have obtained three degrees: an Associate of Science, Welding Engineering Technology from Delta College; a Bachelor of Business Administration from Northwood University; and a Master of Business Administration from Michigan State University. I retain a Master Certification in Project Management from George Washington University, and continue to maintain a Certified Welding Inspector Certification from the American Welding Society.

In 1999, I began employment at Dow Chemical in Midland, Michigan as a Project Manager. My responsibilities included managing the research and development within the Engineering Sciences and Market Development organization throughout the United States and abroad. In detail, my duties included new and emerging chemical process technologies in chemical process computer simulation, lab scale process plant proof design, pilot scale process plant proof design, and commercialization of process plants.

In 2006, I began a position with Consumers Energy in the Learning and Development organization developing standards, processes, and training plans, and enforcing adherence to governing compliance. Also, in this role, I supported gas and electric utilities within Engineering and Project Management service organizations on their projects including defining technical specifications, scope development, providing field management, compliance support, estimating, and risk management. My responsibilities included management of project scope, schedule, budget, and quality.

In 2009, I progressed to the position of Welding Engineer. My responsibilities in that position included technical leadership for a department of multi-discipline technical Subject Matter Experts and technicians on electric generation projects.

In 2011, I accepted a Project Manager position on large electric generation retrofit and upgrade projects. In this role I was onsite managing large projects and multifaceted project teams through development and execution phases of projects.

In 2016, I progressed to the Program Manager role for electric generating plant retirements. In this position, I developed, implemented, and managed program management strategies in the direction of large electric generation asset retirements. In addition, while in this role I supported development and led workforce and community transition planning, maintained relationships with strategic clients, led compliance with governing bodies, and supported providing direction to peer industry companies.

In 2020, I progressed to the Director of Enterprise Project Management - Generation Transformation where my duties include leading a team toward strategy alignment and development with Integrated Resource Planning in the electric generation business, directing development of renewable electric generation assets, providing regulatory support, continued leadership of the asset retirement program strategy, and execution.

PURPOSE OF DIRECT TESTIMONY

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to support the Company's Proposed Course of Action ("PCA") identified in this Integrated Resource Plan ("IRP") and demonstrate that the strategy can be executed consistent with the underlying assumptions in this plan. Specifically, my testimony will support the cost estimates for the various gas-fueled, renewable generation, and battery storage technologies considered in the IRP. I will explain the solar development plan in support of the IRP PCA. My testimony will provide an overview of developing technologies potentially viable in achieving the Company's Net-Zero Carbon Emissions by 2040 planet commitment. Finally, I will discuss the New Covert Generating Facility ("Covert"), Dearborn Industrial Generation ("DIG"), the Livingston Generating Station ("Livingston"), and the Kalamazoo River Generating Station ("Kalamazoo") that the Company proposes to purchase as a result of the 2021 Request for Proposals ("RFPs").

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-41 (JEB-1)	New Gas-Fueled Technology Capital and Operations Cost Assumptions;
Exhibit A-42 (JEB-2)	2021 IRP Capital Costs of Renewable Generation and Battery Storage Technologies;
Exhibit A-43 (JEB-3)	PSA for Covert Plant; and
Exhibit A-44 (JEB-4)	PSA for DIG, Kalamazoo, Livingston plants.

Q. Were these exhibits prepared by you or at your direction?

A. Yes.

SECTION I: GAS-FUELED TECHNOLOGY ASSUMPTIONS

Q. The Company's production cost model, Aurora, included inputs for several different cost and operating parameter assumptions. Are you sponsoring any of the inputs used in Aurora?

A. Yes. I am supporting the capital and operating parameter assumptions utilized by Company witness Sara T. Walz for combined cycle, combustion turbine, and reciprocating internal combustion engine ("RICE") generating resources.

Q. What are the cost assumptions utilized for the various new sources of gas-fueled technologies in the Company's IRP?

A. Exhibit A-41 (JEB-1) provides the capital and Operations and Maintenance ("O&M") cost estimates, and operating performance characteristics utilized for the various gas-fueled technology resource options offered for economic selection against other resources in Aurora.

Q. How did the Company develop its cost estimates for the various gas-fueled technologies?

A. The Consumers Energy engineering and planning teams used publicly available sources, such as the U.S. Energy Information Administration's ("EIA") *Annual Energy Outlook 2019*, as a basis for developing cost estimates for various gas-fueled technology options. EBSILON Professional, a thermodynamic cycle modeling software tool, was used to assess performance characteristics for plant configurations that deviated slightly from the defined EIA plants. For example, combined cycle modeling assumptions were adjusted to account for the utilization of air-cooled condensers as a cooling option, as opposed to mechanical-draft wet cooling towers. The technologies considered include combined cycle, simple cycle, and RICE generating plants. Resulting cost and performance trends are consistent with industry experience and data.

Q. What construction timeline assumptions were employed to assist with labor dollar, mobilization cost, and other cost assumptions?

A. The construction timeline assumptions for the projects were as follows:

- Combined Cycle F- and H-Class projects were assessed to have a three-year duration for construction;
- Simple Cycle F-Class projects were assessed to have a 20-month duration for construction;
- Simple Cycle H-Class projects were assessed to have a 20-month duration for construction; and
- RICE Technology projects were assessed to have a 20-month duration for construction.

Construction daily shifts assumed a labor market premium by using a six-day work week and a 10-hour per day shift to assure a compensated workforce to attract craft. The labor force will be managed in accordance with the National Maintenance Agreement to promote fair and binding labor management practices consistent with prudent industry practice.

Q. Were any indirect costs included in the cost estimates provided?

A. Yes. Indirect costs are included and consistent with the EIA's cost development methodology.

SECTION II: SOLAR MODELING AND DEVELOPMENT

Q. What primary industry source was utilized as the basis for defining the transmission-connected utility-scale solar prototype units in the IRP modeling data assumptions?

A. National Renewable Energy Laboratory's ("NREL") 2019 Annual Technology Baseline ("ATB") report.

Q. Please explain the NREL 2019 ATB report.

A. On an annual basis, NREL publishes a report of several new resource technology projected operating parameters and cost forecasts. The report is publicly available on NREL's website and includes a full narrative discussion on the underlying assumptions, sources, and justifications for the forecasts provided. The detailed forecast for each technology includes a low, mid, and constant (or in some cases, high) outlook of costs, which are defined in the report.

Q. Please explain how the data from NREL was used to develop the transmission-connected utility-scale solar prototype units modeling assumptions.

A. Data extracted from NREL's 2019 ATB report was taken from NREL's "Chicago" proxy location and identified as "Solar - Utility PV." The representative project size of NREL's resource was 23 MW. Additional referenced data includes:

- Net capacity factor (%);
- Capital costs in dollars per kW[1];

[1] Capital and fixed O&M costs provided by NREL were in units of $\$/kW_{DC}$. A conversion factor of 1.3 inverter loading ratio was used to convert from $\$/kW_{DC}$ to $\$/kW_{AC}$. See https://atb.nrel.gov/electricity/2018/pv-ac-dc.html for additional information.

- Annual Fixed Operation and Maintenance Expenses in dollars per kW-year; and
- Federal Investment Tax Credit ("ITC") rates in percentage of capital investment[2].

Q. What is the net capacity factor assumed for utility-scale solar resources?

A. NREL's referenced data projects an 18% net capacity factor in terms of direct current ("DC") power; however, all modeling in Aurora is in terms of alternating current ("AC") power. NREL's report assumed an inverter loading ratio of 1.3 should be used to convert DC to AC. Accordingly, for both transmission and distribution-connected solar prototypes, the assumed capacity factor is 23.4%.

Q. What are the capital costs assumed for utility-scale solar resources?

A. The Company's capital cost forecast is based on an average of NREL's 2019 ATB report low and mid cost outlooks.

Q. Why did the Company use the average of the low and mid cost outlooks and not the constant outlook for its utility-scale transmission-connected solar prototype in this IRP?

A. The constant outlook simply represented a scenario that assumed no change in capital or O&M costs between 2017 and 2050. The Company disregarded this outlook because it assumed there would be no technological or supply chain advancements lowering the cost of solar. Given the current and projected market conditions for solar technology development the Company believes there will be lower costs due to technological and/or supply chain advancements. NREL's mid cost outlook assumes current expectations of price reductions in a "business as usual" solar development scenario. NREL's low cost

[2] Changes to solar ITC levels were made in the January 2021 Consolidated Appropriations Act. The original prototype did not include the ITC extensions however, the extension was incorporated into the Company's cost forecasts in the final calculations made for the PCA.

outlook assumes expectations of potential cost reductions with improved research and development funding, favorable financing, and more aggressive global deployment targets. In reviewing the long-term (2019-2040) forecast of capital costs of solar, the Company compared NREL's low and mid cost outlooks to other respected industry sources of capital cost forecasts. This comparison included (1) an outlook from EIA's February 2020 report on "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies," and (2) a subscription-based forecast from IHS Markit called "US Solar PV Capital Cost and LCOE Outlook data - December 2019." In reviewing these three capital cost forecasts, it was observed that NREL's low cost outlook was extremely close to the EIA's 2019 data point, but below IHS Markit's cost outlook in many years; and NREL's mid cost outlook was above IHS Markit's and EIA's cost outlook in all years. An average of low and mid nominal capital cost values was determined for all years of the study period and is included as the Company's long-term capital cost forecast of transmission-connected solar.

Q. Did the Company use the results of the annual competitive solicitation process, as approved as part of the Company's 2018 IRP, to determine the cost of the transmission-connected utility-scale solar prototype units in the IRP modeling data assumptions?

A. No. The first annual competitive solicitation, pursuant to the Company's approved 2018 IRP, was issued in September 2019 and final contracts were not reached until approximately January 2021. The timing of the 2019 solicitation did not provide sufficient time to use the result of the solicitation in the IRP modeling data and assumptions. The outcome and process of the solicitations for the IRP are discussed in detail by Company witness Keith G. Troyer.

Q. How were capital costs for distribution-connected solar determined?

A. Smaller-scale solar projects interconnected to the distribution system may lose the economies of scale that larger projects realize. A cost premium was determined based on a comparison of the recently signed Power Purchase Agreements ("PPAs") for River Fork Solar – one large utility-scale, transmission-connected PPA (100 MW) compared to Bay Windpower I - a smaller-scale distribution-connected PPA (1.8 MW). The PPA rate on the smaller project was 23% higher than the larger PPA and has been identified as a representative market differential between the two scales of projects.

Q. Why were the NREL 2019 ATB distributed solar resource capital cost outlooks not used for the distribution-connected solar prototype?

A. NREL's 2019 ATB report included an outlook for solar resources referred to as Distributed Commercial Photovoltaic ("PV") and Distributed Residential PV. However, the Company's intention for the distribution-connected solar prototype was to represent projects connected at the 46 kV level and lower; these projects are not designed to be distributed energy resources that would be installed at customer locations. The distribution-connected solar resources included in this IRP are assumed to be 20 MW and below. NREL's distributed solar resource was assumed to be 300 kW for commercial customers and 5 kW for residential customers.

Q. How were solar capital costs assumed to change over time?

A. NREL's 2019 ATB report provided long-term capital cost projections. Each annual data point from the low and mid cost outlook was taken directly from NREL's report, averaged, and converted to nominal dollars for use in the modeling. Under these calculations, solar capital costs are projected to decline through 2030 at a rate of approximately 1% per year on a nominal dollars basis – or 3% per year on a real dollars basis; and then stay relatively flat beyond 2030 in nominal dollars – or approximately 2% continued cost declines, on a real dollars basis. Exhibit A-42 (JEB-2) presents the annual capital costs for new solar technologies for each of the IRP modeling scenarios.

Q. What are the annual fixed O&M costs assumed for solar resources?

A. For both transmission and distribution-connected solar prototypes, the average of NREL's low and mid cost outlooks of fixed O&M were used.

Q. How were ITC's treated for the original solar prototype units?

A. Consistent with NREL's report, ITC was initially assumed at the following percentage levels for all new projects beginning construction in the following years.

A renewable energy facility the construction of which begins	and which is placed in service by December 31	SOLAR- - Qualifies for Investment Tax Credit (ITC) equal to the facility's eligible capital cost times this percentage
during 2016-2019	2023	30%
during 2020	2023	26%
during 2021	2023	22%
	2024 / later	10%

Additional discussion can be found in the direct testimony of Company witness Carolee Kvoriak.

Q. Did the Company account for the ITC extension that was part of the Consolidated Appropriations Act ("CAA") which passed in January 2021 into this IRP?

A. Yes. The ITC extension was incorporated into the Company's capital cost forecasts in the final calculations made for the PCA in accordance with the ITC qualification table below.

A renewable energy facility the construction of which begins	and which is placed in service by December 31	SOLAR -- Qualifies for Investment Tax Credit (ITC) equal to the facility's eligible capital cost times this percentage
during 2016	2020	**30%**
during 2017	2021	**30%**
during 2018	2022	**30%**
during 2019	2023	**30%**
during 2020	2024	**26%**
during 2021	2025 / later	**26% / 10%**
during 2022	2025 / later	**26% / 10%**
during 2023	2025 / later	**22% / 10%**
during 2024 or later		**10%**

Q. Please summarize the Company's plan around solar development as part of its PCA.

A. Under the PCA, the Company will continue acquiring solar additions in annual competitive solicitations. As testified by Company witness Richard T. Blumenstock, the Company is proposing to continue the construction of new solar resources through the study horizon of the IRP and developing a solar glidepath to serve forecasted customer demand needs and prepare for the contract termination of Midland Cogeneration Venture Limited Partnership in the year 2030. This solar glidepath will benefit the Company and customers by giving the necessary time for operating and assessing a system with significant solar generation, to allow for a more gradual impact on customer rates, and to minimize execution risk associated with the development of 4,500 MW of solar by 2030 and 7,800 MW of solar generation by 2040.

Q. Included in Aurora, supported by Company witness Walz, are inputs related to the capital and operation costs for solar generation. Are these cost inputs reasonable?

A. Yes. The inputs are based on NREL's 2019 ABT. The Company believes those projections to be reasonable as they historically have been consistent with the industry.

Q. What type of solar facility would the Company expect to install?

A. The Company would expect to install bifacial modules with central inverters on single axis trackers for the solar to be installed as part of the PCA. The Company anticipates continued technology advancements in solar PV systems, and will take into consideration: all available technologies, capital costs, on-going maintenance, and operational costs when developing specific future solar projects.

Q. Is this consistent with the solar units modeled in the IRP?

A. Yes. As Company witness Walz testified, the Company's IRP modeling was for solar PV, utility-scale, bifacial panels on single axis trackers and assumed Midcontinent Independent System Operator, Inc.'s ("MISO") Effective Load Carrying Capability ("ELCC") of 50%.

Q. How does the Company propose to develop the solar included in the PCA?

A. The PCA proposes to construct solar generation or procure solar capacity through competitively bid Build Transfer Agreements ("BTAs"), Development Asset Acquisitions, Company self-developed/performance projects, or PPAs. Under the PCA, solar capacity – whether owned by the Company, projects purchased from developers, or purchased through PPAs – would be awarded based upon a competitive solicitation process. The Company's annual competitive solicitation process is explained in detail by Company witness Troyer.

Q. How does the Company propose to develop and submit bids in the competitive solicitation?

A. The Company would perform early-stage development – acquiring real estate and local permits, applying for generator interconnection agreements, performing preliminary engineering, obtaining firm prices for the acquisition of equipment and construction services, establishing plant performance expectations, and bid into the competitive procurement process like other third-party bidders.

Q. Under the PCA, if the Company's projects are selected through the competitive bidding process, can the Company feasibly develop the amount of solar in the PCA?

A. Yes; however, the Company's PCA does not assume that Consumers Energy would be constructing the solar unilaterally. Under the PCA, the Company believes that third-party development would be an integral component to the plan, with developers and independent power producers creating more flexibility, diversity of locations, competitive pricing, and capability to develop the amount of solar in the plan.

The PCA calls for the development of solar over the course of several years, utilizing a maximum 500 MW per year incremental approach. This incremental approach to developing the amount of solar under the PCA is reasonable because:

(i) The approach anticipates technological advances in the early years of the plan that reduce costs;

(ii) The Company will gain important development, construction, and operating experience during the early years of the plan;

(iii) The Company will apply experience and cost enhancements to achieve the pace of build in the plan to improve overall performance and costs; and

(iv) The Company anticipates third-party development opportunities improving locational diversity, project development timeframes as compared to the Company, and/or lower costs for customers.

Q. Is the Company intending to constrain the solar development to 500 MW per year as identified in the PCA?

A. Yes; however, with the proposed improvements to the annual competitive procurement process as discussed by Company witness Troyer, the Company would have greater flexibility to under or over procure 500 MW of solar year to year based upon a balanced approach to customer costs, value, and financial impacts of the Company in its decision making process.

Q. How long does it typically take to develop and construct a solar facility?

A. Whether a solar facility is owned by the Company or a developer, the typical solar development/construction process takes three to five years as reflected by the 2019 and 2020 IRP solicitations discussed by Company witness Troyer. At a high level, the development process (approximately two to three years) involves site selection, land acquisition, building community relationships, community education, environmental impact studies, permitting, arranging for the electrical interconnection, engineering, proper regulatory reviews and approvals, and contracting for the equipment and construction services prior to commencement of construction. The construction process (approximately 18 months to two years) involves site mobilization/demobilization, site prep, transmission system network upgrades, installation of solar racking, modules, inverters, substation construction and generator step-up transformer installation, performance testing and acceptance, site reclamation, and revegetation.

Some third-party developers could be at different stages of this process within Michigan as the PCA study period progresses compared to the Company. After a competitive bid process, the Company anticipates that a portion of the projects over the time period would come from a diverse mixture of Company-owned projects, third-party development, and PPAs.

Q. What kind of land resources will be necessary for the Company to execute the build of solar capacity identified in the PCA?

A. Real estate is a critical resource for solar development, especially at the projected scale over the PCA period. A solar facility typically requires between six to eight acres per megawatt of capacity. The total real estate dedicated for 7,800 MW of solar through 2040 is approximately 47,000 to 62,000 acres. Such real estate will need to be geographically diverse to reduce significant electric system disruptions due to cloud cover, meet electric system standards, and be safely integrated into existing electrical infrastructure. Geographic diversity may help to mitigate potential community concerns over "too much" solar installed in one area and provide additional optionality to ensure the locations providing a balance of economic costs, commodity value for customers, and system resiliency.

Q. Is it feasible to devote such a quantity of land to solar energy?

A. Yes. The Company began evaluating the land resource in the Lower Peninsula by searching for undeveloped land that would support solar development, in other words, land with no forests or urban development. The review was limited to parcels in excess of 100 acres with a single owner, using U.S. Geological Survey, 20141010, NLCD 2011 Land Cover (2011 Edition, amended 2014) and a Michigan parcel dataset purchased from

CoreLogic - Version: 2018 Quarter 1. A parcel of 100 acres, corresponding to a solar facility of 20 MW, was considered to be the minimum parcel size for utility-scale solar. At 20 MW or larger, reasonable economies of scale are available. The Lower Peninsula has 8,200 parcels meeting the sizing and ownership criteria, totaling 1,200,000 acres. Dedication of some 30,000 acres of land, or 1.6% of the 1,200,000 acres, on an economic basis across such a large potential is very feasible. As discussed previously, the competitive procurement process will be utilized to help keep costs competitive and third-party participation in the development and deployment of the planned PCA solar can also provide geographical and technical diversification over the plan period.

Q. What other land issues will the Company consider in siting solar energy projects?

A. The Company is committed to the best land use practices for Michigan in its development processes, and will pursue working with schools, government entities, and others to site solar in a way that provides lease revenues for public purposes.

Q. Would the use of third-party developers impact the land acquisition necessary for the solar development?

A. Yes. The Company will be seeking geographic diversity for this solar program and anticipates multiple siting approaches amongst the third-party developers.

Q. Please describe the labor, equipment, and material procurement process the Company will need to undertake for the potential construction of the solar facilities in the PCA.

A. Evaluation of the risks associated with construction will be a key factor in the project selection process. The surety of the solar supply chain, consisting primarily of solar panels and construction labor, will be critical for all parties building solar, given the large volumes of equipment and construction services to be procured in the middle years of the PCA. Forming strategic alliances will enhance the supply chain in both construction labor and materials for participants in this solar build to assure adequate quality materials, equipment, and labor are available to complete the construction of the large amounts of solar anticipated in the PCA. The Company anticipates utilizing a competitive bidding process as necessary with third parties to develop and execute future alliances to secure the ability to meet the PCA.

Q. How will the new solar facilities interconnect to the grid?

A. Interconnection will be a function of location, as the Company intends to seek sites (as a criterion in the competitive procurement process) in reasonably close proximity to high voltage distribution and transmission lines and locate the solar facilities across a broad geographic footprint. Close proximity to the interconnection will reduce the overall cost of installation by reducing the materials cost to reach the grid and reducing corresponding electric line losses.

Q. What challenges are there toward the implementation of a large solar build?

A. There are three broad challenges for the Company to plan for as development of the implementation strategy matures:

(i) **<u>Cost:</u>** Industry projections used in the analyses assume a declining cost of solar during the early years of the plan; however, there is no guarantee that the costs would align. A competitive procurement process is the method the Company intends to use to procure economic projects providing maximized value for customers. Strategic alliances formed through competitive bidding may be an effective means to manage critical parts of the solar supply chain, such as solar panel manufacturing as discussed previously. Strategic alliances may provide an opportunity to have known competitive cost rates for solar development over a given segment of the PCA timeframe while allowing for the capture of technology driven cost declines;

(ii) **<u>Permitting</u>**: The local regulatory landscape for renewable energy assets continues to evolve as the industry grows. Using wind power development as a proxy for solar development in the state of Michigan, some local communities have changed zoning requirements or introduced wind moratoriums to specifically halt or limit the amount of wind development and siting; therefore, the Company would anticipate similar responses to solar development in the state if overly concentrated in particular geographic locations. The solar radiation resource is more evenly distributed across the state as compared to the wind resource, which should reduce the possibility of significant concentration. It is critical and necessary to ensure not only the Company, but third-party developers engage with potentially affected and impacted communities through implementation of this, or any future renewable energy build; and

(iii) **<u>Real Estate:</u>** As the plan progresses over time, acquisition of large parcels in appropriate locations at reasonable prices could present a secondary challenge. The challenges being considerations such as pricing, the proximity of the land to existing infrastructure, the zoning requirements of particular communities, or environmental sensitivities.

Q. Please describe Michigan workforce and economic benefits with the development of solar in the PCA.

A. The Company's PCA assumes the solar additions, used predominately to replace retirement of Company-owned generating resources and terminating contracts, are in the Lower Peninsula of Michigan, MISO Zone 7. The development of solar to replace resources existing in Michigan today continues to support the prosperity of the state's local communities, workforce opportunities created for people by way of re-skilling of the Company's workforce, new job skill development, and reassignment from retired assets.

<u>SECTION III: WIND MODELING AND DEVELOPMENT</u>

Q. Explain the nature of the wind generation prototype units.

A. The Company assumes that any expansion of wind capacity could occur either in state or out of state. As the state of Michigan continues to approach saturation of wind build-out, particularly after the assumed expansion to comply with the Renewable Portfolio Standard in Public Act 342 of 2016 ("Act 342"), feasibility of in-state wind development has become a concern for the Company. Recent opposition to and moratoriums on construction of future wind facilities in Michigan's thumb region, and lower wind resource areas (i.e. achievable lower net capacity factors) throughout the remainder of the state suggest that additional wind build-out in Michigan may not be cost-effective nor a feasible option. The wind projects offered for selection in the Company's IRP represent wind built in the state of Michigan and also in the MISO West region, using Iowa as a proxy location. For modeling purposes, the Company developed wind prototypes at an installed capacity of one 200 MW prototype located in MISO Zone 7, one 400 MW prototype in MISO-West, and an assumed capacity credit awarded at MISO's ELCC for wind of 16.6%[3]. For details regarding the operating parameters and assumed costs for these resources, please see Exhibit A-42 (JEB-2).

Q. What is the impact on energy and capacity value for the out-of-state wind prototype, assuming expansion occurs in Iowa?

A. To develop wind generation prototypes in Iowa, the Company assumed that in lieu of construction of a dedicated transmission line to import capacity and energy from Iowa into Michigan, the energy produced would be sold in Iowa, with an equivalent amount of energy purchased in Michigan. Comparison of historical energy market prices in Iowa versus Michigan indicates that energy prices in Iowa can be expected to be approximately $4.77/MWh lower than those in Michigan.[4] This price differential was included in the modeling for all out-of-state wind prototype units to reflect the assumption that these assets provide lower energy revenues to customers than in-state units. While it is assumed that

[3] The ELCC provided is effective as of December 2019 and used in all Aurora modeling. In December 2020 (after initiation of model development), MISO issued a draft report that projected an ELCC for wind re-stated at 16.3% but has not been reflected in this IRP.

[4] The $4.77/MWh price differential represents the three-year average difference in locational marginal prices between Consumers Energy's load zone and Iowa for years 2017-2019.

the capacity from these resources would also be sold in Iowa, which falls within Zone 3 in MISO, the modeling assumes no long-term significant price differential on the capacity prices between MISO's Zone 7 and Zone 3.

Q. Are there non-economic risks associated with the expansion of wind in Iowa?

A. Yes. First, while not quantified in the model simulations, wind produced and sold in Iowa would provide no Renewable Energy Credits necessary to comply with the Renewable Portfolio Standard in Act 342 to serve 15% of energy requirements with renewable energy by 2021, and would not continue to support a Company goal of maintaining the 15% target beyond 2021 even if the projects were economic. Second, wind project development in Iowa (construction, operation, maintenance, etc.) provides no economic benefit to the state of Michigan. Third, the Company has experience with development and operation of wind in Michigan, but is unfamiliar with local regulations, requirements, and communities in Iowa; and the Company does not have experience with other state regulatory bodies.

Q. What are the potential benefits that could be realized for selection of wind resources in Iowa?

A. The primary advantage of expansion of wind in Iowa is feasibility. While additional expansion of wind construction in Michigan is challenged at this time, wind development in Iowa continues. Additionally, as projected in NREL's 2019 ATB, (TRG2 and 3) Iowa wind is projected to have significantly higher capacity factors than wind built in Michigan.

Q. Please explain the data used from NREL to develop the wind prototype units.

A. Data extracted from NREL's 2019 ATB report for new wind include:

- Capital costs in dollars per kW; and
- Annual O&M costs in dollars per kW-year.

Q. What are the capital costs assumed for utility-scale wind resources?

A. The Company's capital cost forecast is based on an average of NREL's 2019 ATB low, mid cost, and constant outlooks for out-of-state wind and NREL's 2019 ATB low, mid cost, and constant outlooks (starting point was adjusted with recent wind acquisitions) for in-state wind.

Q. How were wind capital costs assumed to change over time?

A. Capital costs provided in NREL's 2019 ATB report are provided in 2017 dollars and a year-over-year cost increase (or decrease) was observed from these annual values. However, for improved efficiency of modeling, an average of the year-over-year cost increases (or decreases) was calculated for the near-term 20-year period from 2019 through 2040 as a 2.88% average cost increase. This capital cost escalation rate was assumed for all years of the planning period. In-state wind capital dollars were adjusted to assume a starting point consistent with current wind acquisition negotiations. A summary of the annual cost of capital for all renewable energy and battery storage technologies, by scenario, is presented in Exhibit A-42 (JEB-2). Lines 1 through 9 present base capital cost assumptions under the Business as Usual scenario; lines 10 through 18 present capital costs under the Emerging Technology scenario; lines 19 through 27 present capital costs under the Environmental Policy scenario; and lines 28 through 36 present capital costs under the Advanced Technologies scenarios.

Q. What are the annual fixed O&M costs assumed for wind resources?

A. The average of NREL's low, mid, and constant cost outlooks of fixed O&M were used for out-of-state wind and internally developed outlooks of fixed O&M were used for in-state wind.

Q. Explain how Production Tax Credits ("PTCs") were treated on the wind prototype units.

A. Consistent with NREL's 2019 ATB assumptions, PTC was provided at the assumed dollar per MWh rate of between $25/MWh and $32/MWh during the planning period, and at the following percentage levels: for wind in commercial operation by year-end 2021, 80% PTC is assumed; for wind in commercial operation by year-end 2022, 60% of PTC is assumed; for wind in commercial operation by year-end 2023, 40% of PTC is assumed; and for wind in commercial operation by year-end 2024, 60% of PTC is assumed. For any wind in commercial operation in year 2025 and beyond no PTC is assumed.

Q. Have PTC updates made in the CAA been incorporated into this IRP?

A. No.

SECTION IV: COST OF BATTERY STORAGE

Battery Storage

Q. What primary industry source was utilized as the basis for defining battery storage prototype units in the IRP modeling data assumptions?

A. Consistent with the methodology described in Section II, the source of data for battery storage prototypes is the NREL 2019 ATB report.

Q. Please explain how data from NREL was used to develop the battery storage prototype units modeling assumptions.

A. Battery storage data from NREL's 2019 ATB report corresponds to a four-hour duration storage device with a 15-year life. Detailed documentation supporting the representative unit can be found in the publicly available document entitled "Cost Projections for

Utility-Scale Battery Storage," published by NREL in June of 2019. Additional referenced data includes:

- Round-trip efficiency (%);
- Capital costs in dollars per kW; and
- Annual Fixed O&M expenses in dollars per kW-year.

Q. What is meant by round-trip efficiency ("RTE") and what value was assumed for battery storage resources' RTE?

A. RTE refers to the battery storage system efficiency through a cycle of charge and discharge. The RTE on a battery storage system may quantify the energy losses of the facility required for cooling or powering of facility equipment. NREL's referenced data projects an 85% RTE for the battery storage prototype.

Q. What are the capital costs assumed for battery storage resources?

A. The Company's capital cost forecast is based on an average of NREL's 2019 ATB low and mid cost outlooks.

Q. Why did the Company use the average of the low and mid cost outlooks and not high for its battery storage prototype in this IRP?

A. NREL's definitions for the low, mid, and high outlooks for battery storage are developed differently than the low, mid, and constant outlooks discussed for solar prototypes. For battery storage capital cost forecasting, NREL considered 25 datasets and defined the low capital cost outlook as the minimum forecast of the 25 datasets; the medium capital cost outlook as the median of the 25; and the high capital cost outlook as the maximum of the 25 outlooks. The Company was initially inclined to use the mid capital cost outlook since the median of the 25 datasets seemed the most likely to be representative of future costs. However, in internal discussions with subject matter experts, there was an acknowledgement of the growing expectation that battery storage costs are likely to see continued cost declines, given a number of factors, including, but not limited to – growth of electric vehicle adoption, growing awareness of the importance of electric grid reliability (and that battery storage may provide a solution, accelerating adoption of battery storage as a supply resource), and advancements in battery storage technologies, research, and development.

In addition, and similar to the discussion included in Section II, the low, mid, and high NREL capital cost forecasts were compared to other industry publications. Ultimately, as in the case of the solar capital cost forecast, the Company decided to use the average of the low and mid capital cost forecasts from NREL for the battery storage prototype in this IRP.

Q. How were battery storage capital costs assumed to change over time?

A. The NREL methodology for capital cost escalation is discussed beginning on page 3 of the referenced report, "Cost Projections for Utility-Scale Battery Storage," which were translated in the ATB as long-term capital cost projections. Each annual data point from the low and mid cost outlook was taken directly from NREL's report, averaged and converted to nominal dollars for use in the modeling. Under these calculations, battery storage capital costs are projected to decline through 2030 at a rate of approximately 4% per year on a nominal dollars basis – or 6% per year on a real dollars basis; and then stay relatively flat beyond 2030 in nominal dollars – approximately 2% continued cost declines, on a real dollars basis. Exhibit A-42 (JEB-2) presents the annual capital costs for new battery storage technologies for each of the IRP modeling scenarios.

Q. What are the annual fixed O&M costs assumed for battery storage resources?

A. Fixed O&M costs for battery storage are calculated as the average of NREL's low and mid cost outlooks of fixed O&M from the ATB.

Q. The direct testimony of Company witness Nathan J. Washburn discusses four different battery storage prototypes considered in this IRP. How do the modeling inputs vary for each of the four prototypes?

A. From a modeling parameter basis, three of the battery storage prototypes – energy and capacity, distribution asset upgrade deferral, and ancillary service market – all use the same assumptions for RTE, capital cost, and fixed O&M costs. These three prototypes differ in the revenues or value accounted for as an offset to the fixed O&M costs. More information regarding those values can be found in the direct testimony of Company witness Washburn. The fourth prototype, a hybrid solar and storage co-located resource, required additional calculations to determine capital costs, fixed O&M, as well as increased capacity factor at the solar facility.

<u>**Solar and Storage Hybrid**</u>

Q. Please discuss the calculations made to determine capital cost forecasts for the solar and storage hybrid prototype.

A. Data sources for capital costs used for the hybrid prototype are consistent with those discussed earlier in my testimony (NREL's low and mid capital costs for solar and for storage). However, the nature of the hybrid facility requires consideration of cost reductions achieved by the co-location of the two resources. A publicly available report, published by NREL in November 2018, "2018 U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Costs Benchmark," projects the savings at 8%, when co-located and DC-coupled[5]. Furthermore, there are some electrical components required for conversion to AC that can be shared by the facility, providing an additional 1% savings. Finally, hybrid prototype for this IRP was designed to enhance the benefits realized by each of the resources – specifically, the hybrid resource was designed in two specific ways: (1) the co-location of battery storage improves the performance of the solar resource; and (2) the co-location of the solar resource provides opportunity to earn ITC on the battery storage investment. Section III of Company witness Washburn's testimony includes further discussion on these specific designs. The result of the prototype design for the hybrid resource required the following detailed calculations of capital costs:

- First, the cost of the solar capacity of the hybrid facility was calculated. The same capital cost forecast that was developed and described in Section II of my testimony was used to determine the total cost of the 100 MW solar portion. Specifically, 100 MW was multiplied by the average of NREL's low and mid forecasts on a $/kW$_{DC}$ basis and reduced by 1%, to account for shared DC equipment between the two resources (solar and storage). That quantity was multiplied by the inverter load ratio of 2.0, as described in the testimony of Company witness Washburn, and an interconnection cost of $2 dollars per kW was included for a final cost of the solar AC portion (in dollars);

- Next, the cost of the 30 MW storage capacity of the hybrid facility was calculated. The average of NREL's low and mid forecasts on a $/kW$_{AC}$ basis was multiplied by 30 MW and added to the same interconnection rates for a final cost of the AC storage portion (in dollars);

- Then the total cost (in dollars) of the solar portion was added to the total cost of the storage portion;

- Based on the estimated savings from NREL, the total system cost was then reduced by 8%, to account for the shared site costs, discussed above; and

- Finally, a $/kW$_{AC}$ capital cost was calculated, with the solar capacity as the denominator (which was observed to be common in industry publications).

[5] Page iv discusses that the co-location of these resources produces cost savings by reducing shared site costs such as site preparation, land acquisition, permitting, interconnection, installation labor, hardware, and overhead.

Q. How were capital costs for the solar plus storage hybrid facility assumed to change over time?

A. Various publications reviewed for this prototype included discussions that co-location solar plus storage sites are expected to gain efficiencies and realize reductions in costs. Given the capital cost escalations included in this IRP for solar and those for storage, the Company decided to use the average of the year-over-year percent changes for both solar and storage. Resultantly, capital costs are projected to decline through 2030 at a rate of approximately 2% per year on a nominal dollars basis – or 5% per year on a real dollars basis; and then stay relatively flat beyond 2030 in nominal dollars – approximately 2% continued cost declines, on a real dollars basis. Exhibit A-42 (JEB-2) presents the annual capital costs for the solar plus storage hybrid facility.

Q. What are the annual fixed O&M costs assumed for the solar plus storage hybrid resource?

A. As discussed in the testimony of Company witness Washburn, the hybrid facility is assumed to have a 30-year life instead of the 15-year life assumed for other battery storage prototypes. To account for the extension of life of the storage portion, additional costs are included in the fixed O&M for augmentation or replacement of the batteries to achieve the life extension. An increase of approximately 25% was applied to the projected fixed O&M of battery storage costs from NREL's ATB.

Q. What are the assumptions of capacity factor on the solar portion of the hybrid resource?

A. Please see the testimony of Company witness Washburn for a detailed discussion regarding the increased output of the hybrid facility, compared to expected generation from a standalone solar prototype.

SECTION V: POTENTIAL EMERGING TECHNOLOGIES TO SOLVE FOR NET ZERO CARBON EMISSIONS IN 2040

Q. Were any new and emerging zero carbon technologies considered as generation prototypes in this IRP to achieve the Company's Net Zero Carbon Emissions goal in 2040?

A. No. The Company did not include prototypes of emerging carbon technologies in the Aurora model. The Company has researched a set of technologies with the potential to help close the carbon emissions gap for all sources (owned, contracted, and market purchases) in 2040. These technologies are:

- Carbon Capture and Sequestration – this system removes carbon dioxide gas from the flue gas exhaust, converts it to a liquid phase which is then sequestered underground in a long-term storage reservoir;
- Supercritical Carbon Dioxide Power Plants – uses a supercritical carbon dioxide power plant cycle in lieu of the conventional water and steam cycle;
- Hydrogen – hydrogen is created through various processes (hydrolysis for example), stored for later use, and used for power production by way of a conventional gas turbine or fuel cell;
- Long-Duration Energy Storage – achieved with a hydrogen storage system, compressed air system, or a battery with longer than a four-hour duration;
- Nuclear Power – uses a modular pressurized water design to generate electric power using nuclear energy; and
- Carbon Offsets – consists of nature-based solutions such as reforesting lands previously forested, renewable natural gas systems capturing landfill emissions

or other sources and reusing them, and Direct Air Capture system that directly removes carbon dioxide from the air making it a negative carbon approach.

Prototypes for the above technology solutions were not made available to the Aurora model for economic selection because their technical readiness levels and/or costs are not yet comparable to other power generation technologies and would not be economically selected within the Aurora model. However, the Company is able to identify the carbon emissions gap from the electric business as described by Company witness Heather A. Breining to identify those technologies potentially suitable in the future to achieve the Company's goal of Net Zero Carbon Emissions.

Q. What barriers and opportunities do you see with the technology solutions identified in the above question?

A. For each of the technologies above:

- Carbon Capture and Sequestration – The barriers are capital investments, sufficient space to locate the carbon capture/sequestration equipment and efficiency losses – unit output reduction of 15-20% are expected from operating this type of system. The opportunities include application to existing and new natural gas technologies and ability to provide reliable power versus retrofitting existing coal units, potential for governmental policy incentivizing this technology, and the favorable geology of Michigan for underground carbon sequestration;

- Supercritical Carbon Dioxide Power Plants – The barriers are the capital costs which are 33% higher than a new natural gas combined cycle unit, higher fixed O&M expenses but lower variable O&M expenses. The opportunities include smaller power components and less carbon capture equipment to facilitate underground sequestration. Additionally, the geology of Michigan is favorable for underground carbon sequestration;

- Hydrogen – The barriers include a significantly lower heating value compared to natural gas on a volumetric basis, increasing the size and cost of the equipment. The use of hydrogen fuel cells is challenged on scalability and affordability (three to four times higher than a gas turbine). The opportunities include suitable geology in Michigan for long duration storage promoting electric supply reliability, and the ability to fire hydrogen in upgraded existing natural gas generating units;

- Nuclear Power – The barriers include the long-standing nuclear waste disposal issue requiring a federal government commitment to a long-term storage solution, and costs that are three to four times higher than the comparable natural gas-fired technology. The opportunities are smaller scale design and efficiency of nuclear reactors having a proven zero carbon reliable source of energy and capacity; and

- Carbon Offsets – The barriers include the current lack of standardization of verifiable climate benefits for the nature-based solutions and costs for the direct air capture technology. The opportunities are the ability to use direct air capture to remove carbon dioxide from the air and sequester the captured carbon dioxide using Michigan's suitable geology.

In the near term, affordability and technical feasibility (e.g. capital and O&M cosst, land availability, process efficiencies, etc.) are the primary challenges to the deployment of the zero-carbon technologies listed above. The Company intends to continue to collaborate with other research institutes such as the Electric Research Power Institute and the Department of Energy to achieve the Company's Net Zero Carbon Emissions in 2040.

<u>SECTION VI: EXISTING GAS PLANT ACQUISITIONS</u>

<u>Covert Plant</u>

Q. Please describe the Company's plan to purchase and acquire the Covert Plant on or about May 31, 2023.

A. As explained in the direct testimony of Company witnesses Blumenstock and Troyer, the purchase of the Covert Plant is part of an overall plan to replace D.E. Karn ("Karn") Units 3 and 4, which the Company is proposing to retire in 2023, and J.H. Campbell ("Campbell") Units 1, 2, and 3 which the Company is proposing to retire in 2025. The plan to acquire the Covert Plant is one of the measures the Company has taken to address the need for additional capacity to support the retirement of Karn Units 3 and 4 and Campbell Units 1, 2, and 3.

Q. Please generally describe the Covert Plant?

A. The Covert Plant is an existing 1,176 MW (nameplate) combined cycle natural gas-fueled electric generating plant commissioned in 2004 which currently offers generation into the PJM Interconnection, LLC ("PJM") market. The Covert Plant is currently owned by New Covert Generating Company, LLC which is a wholly owned indirect subsidiary of Segreto Power Holdings, LLC. The Covert Plant is located in Covert, Michigan.

Q. Was the selection and purchase of the Covert Plant a prudent decision?

A. Yes. As explained by Company witness Troyer, the Covert Plant was selected in the 2021 RFP which was a competitive solicitation process conducted by an independent third party. Furthermore, the selection of the Covert Plant meets the planning objectives, energy, and capacity needs of the Company as explained by Company witness Blumenstock. The Covert Plant is an existing facility with a proven track record of being efficient, flexible, and available when called upon to operate. The Covert Plant has been operating in either the PJM or MISO markets since it began operation in 2004 and has a proven track record under multiple dispatch profiles that have included baseload, intermediate, and peaking dispatch.

Also, the purchase of the Covert Plant will allow Consumers Energy to continue to lower emissions and capitalize on lower natural gas prices while providing customers with immediate value. The Company performed an extensive due diligence evaluation and fatal flaw analysis showing that the Covert Plant combined cycle units will provide lasting value to Consumers Energy's customers.

Q. What is the purchase cost of the Covert Plant?

A. The purchase cost of the Covert Plant is $815 million.

Q. Please describe the design of the Covert Plant.

A. The Covert Plant is an extremely flexible and reliable plant which was designed to take advantage of rapid-changing load and market conditions. Unlike a traditional combined cycle plant with two large frame combustion turbines and one steam turbine, the Covert Plant has three mostly independent, combined cycle units composed of a Mitsubishi M501G1 gas turbine and single steam turbine. Each unit has its own heat recovery steam generators ("HRSG") with supplemental duct firing. The gas turbines and duct burners fire natural gas that is provided via an interconnect agreement with ANR Pipeline Company ("ANR Pipeline"). The gas turbines and duct burners do not fire fuels other than natural gas. More details regarding the plant fuel supply arrangements can be found in Company witness Brian D. Gallaway' s testimony. The M501G turbine designs are among the most common in the power industry and have a long-proven track record with approximately 80 units put into operation since 1997. The Covert Plant gas turbines were recently upgraded to produce more electrical power at a higher rate of efficiency so the units have a nominal heat rate of 7,000 Btu/kWh. Finally, the Covert Plant's availability has routinely averaged above 89% for the past five years.

Q. What makes the Covert Plant so flexible and reliable?

A. As explained above, the Covert Plant is composed of three "one-on-one" combined cycle units. The three smaller independent turbines and HRSGs allow start-up and warm-up times to be shorter than a traditional 1,100 MW combined cycle plant. This allows quicker response to changing load conditions along with much lower fuel consumption during start-ups. The Covert Plant can also produce 67% of its design output during maintenance or failure of any one of the three combustion turbines or steam turbines. In comparison, if a traditional combined cycle plant loses one of its two combustion turbines, the output is reduced by 50%, and if the steam turbine fails, the plant must be taken off-line.

Q. Does the Covert Plant offer additional flexibility?

A. Yes. The three one-on-one combined cycle units have a much lower minimum load point than traditional ("2x1") combined cycle plants – two combustion turbines and one steam turbine. Traditional 2x1 plants have a minimum load point of 50% of its rated output – so a 1,200 MW plant would have a minimum load point of approximately 600 MWs. In contrast, the Covert Plant has a minimum load point of approximately 200 MWs with one unit operating at 50% load.

Q. What are the expected typical annual costs associated with operating the Covert Plant including fuel, O&M, and environmental compliance?

A. The projected annual costs to operate the Covert Plant are primarily addressed by Company witnesses Walz and Norman J. Kapala. In addition, Company witness Kvoriak addresses projected property taxes and Company witness Breining addresses environmental compliance.

Q. What is the fuel source of the Covert Plant?

A. The current and expected fuel arrangements for the Covert Plant are addressed by Company witness Gallaway. As explained by Mr. Gallaway, the Covert Plant connected to ANR Pipeline through a 3.5 mile long, 20" lateral owned and operated by ANR Pipeline.

Q. What is required to allow the Covert Plant to switch from serving the PJM market to the MISO market, where the Company's customers are located?

A. The existing switchyard at Covert Plant already has the necessary high voltage equipment to export electric power to the MISO market. Since the Covert Plant has not served the

MISO market in recent years, an interconnection application has been, or will be soon, submitted to allow the Covert Plant to operate in the MISO market when the Covert Plant title is transferred to Consumers Energy.

Q. What is the expected schedule for interconnecting the Covert Plant to the MISO market?

A. The anticipated date that an executed Generating Interconnection Agreement and connection of the Covert Plant into the MISO market is on or before May 31, 2023.

Q. Does the Company expect to incur any additional costs, beyond what is included in the Purchase Sale Agreement ("PSA"), related to interconnecting the Covert Plant to the MISO market?

A. No. The Covert Plant Seller will (at its own expense) undertake all commercially reasonable efforts necessary, proper, or advisable, and proceed diligently and in good faith, as promptly as practicable, to achieve by stated deadlines interconnection of the Covert Plant with MISO, or other equivalent arrangements reasonably acceptable to the Company However, the PSA does provide for cost sharing between the Company and the Covert Plant if interconnection costs exceed $2 million (i.e. the interconnection cap). If such excess interconnection costs exceed $12 million, the Company has the right to terminate the PSA.

Q. What type of pollution control equipment is included with the Covert Plant?

A. The individual units of the Covert Plant are equipped with Selective Catalytic Reduction and Carbon Monoxide catalyst to control emissions within the approved air permit for the facility. Carbon dioxide emissions from a gas-fired unit are much lower than that from the Campbell coal-fired units so an overall reduction in carbon dioxide is expected with the purchase of the Covert Plant, as discussed in Company witness Breining's direct testimony. All other pollutants are generated at low levels where pollution control equipment is not required to meet the Covert Plant's air permit requirements. Company witness Breining presents additional detail on the emissions outlook of the PCA, which includes the purchase of the Covert Plant in 2023.

Q. What is the schedule for obtaining the necessary environmental permits to operate the Covert Plant?

A. Company witness Breining discusses environmental permitting related to the Covert Plant. As explained by Company witness Breining, the Company would not be required to obtain any additional air and/or water permits due to the purchase of the Covert Plant. The Covert Plant's existing permits would simply need an administrative change transferring them into the Company's name. The Company will comply with all permits currently in place.

Q. Please explain the transaction costs that the Company has or expects to incur as a result of the purchase of the Covert Plant.

A. The transaction costs that the Company has or expects to incur as a result of the purchase of the Covert Plant include title insurance, transfer tax, survey, legal, and miscellaneous due diligent costs. These costs amount to $5 million and represent investment costs that the Company will reasonably and prudently incur as a result of the acquisition of this plant.

Q. Has the Covert Plant purchase agreement been signed by the parties?

A. Yes. The contract for the purchase of the Covert Plant was signed in June 2021. The contract represents a PSA which will allow the Company to take full ownership of the Covert Plant on or around May 31, 2023. The Covert Plant PSA has been included as Exhibit A-43 (JEB-3).

Q. Has the Company's Board of Directors approved the purchase of the Covert Plant?

A. Yes. The CMS Energy Board of Directors approved the purchase of the Covert Plant on June 11, 2021.

Q. Is the Company requesting cost pre-approval of the purchase price of the Covert Plant in this IRP proceeding?

A. Yes. As explained by Company witness Blumenstock, the Company is proposing to purchase the Covert Plant as part of the PCA proposed in this case. Since the Company will incur the cost to purchase the Covert Plant within three years after the Commission's expected order approving this IRP, the Company requests that the Commission specifically approve the acquisition and total purchase costs of $815 million, which is inclusive of transaction costs, as reasonable and prudent for cost recovery purposes pursuant to MCL 460.6t(11) and all other applicable law.

DIG, Kalamazoo, and Livingston Plants

Q. Please generally describe the DIG, Kalamazoo, and Livingston plants?

A. The DIG Plant consists of an existing combined cycle natural gas-fueled electric generating plant commissioned in 2001 and a simple cycle natural gas-fired generating unit commissioned in 1999, totaling 770 MW. DIG also has three natural gas/blast furnace gas boilers that are partially fired with waste gas from AK Steel that provide high quality steam to AK Steel and Ford Rouge sites. The DIG Plant is located in Dearborn, Michigan.

The Kalamazoo Plant is a 75 MW simple cycle natural gas-fired electric generating plant commissioned in 1999. The Kalamazoo Plant is located in Comstock, Michigan.

The Livingston Plant is an existing 156 MW simple cycle natural gas-fired electric generating plant commissioned in 1999. The Livingston Plant is located in Gaylord, Michigan.

All three aforementioned plants are currently owned by CMS Enterprises Company, LLC ("CMS Enterprises") which is a wholly owned subsidiary of CMS Energy Corporation located in Jackson, Michigan.

Q. Please describe the Company's plan to purchase and acquire the DIG, Kalamazoo, and Livingston plants on or about May 2025.

A. As explained in the direct testimony of Company witnesses Blumenstock and Troyer, the purchase of the DIG, Kalamazoo, and Livingston plants is part of an overall plan to replace Karn Units 3 and 4, which the Company proposes to retire in 2023, and Campbell Units 1, 2, and 3, which the Company is proposing to retire in 2025. The plan to acquire the DIG, Kalamazoo, and Livingston plants, totaling 1001 MW of capacity, is one of the measures the Company has taken to address the need for additional capacity to support the retirement of the Karn and Campbell units.

Q. Was the selection and purchase of the DIG, Kalamazoo, and Livingston plants a prudent decision?

A. Yes. As explained by Company witness Troyer, the DIG, Kalamazoo, and Livingston plants were selected in a competitive solicitation process conducted by an independent third party. These plants were submitted into the competitive solicitation as a single bid. Furthermore, the selection of the DIG, Kalamazoo, and Livingston plants meets the planning objectives and energy and capacity needs of the Company, as described by Company witness Blumenstock. The DIG Plant is an existing facility with a proven track record of being efficient, flexible, and available when called upon to operate. The DIG plant has a strong history of reliably serving its customers. The DIG, Kalamazoo, and Livingston plants have been operating in the MISO market since they began operation as early as 1999. All three plants have been successfully operated under multiple dispatch profiles that have included baseload, intermediate, and peaking service.

Additionally, the purchase of the DIG, Kalamazoo, and Livingston plants will allow Consumers Energy to continue to lower emissions and capitalize on today's lower natural gas prices while providing customers with immediate value. The Company performed an extensive due diligence evaluation and fatal flaw analysis showing that the DIG, Kalamazoo, and Livingston plants will provide lasting value to its customers.

Q. What is the purchase price of the DIG, Kalamazoo, and Livingston plants?

A. The purchase cost of the DIG, Kalamazoo, and Livingston plants is assumed to be $530 million.

Q. Please describe the design of the DIG Plant.

A. The DIG Plant was designed to serve as a combined heat and power plant serving some of Michigan's largest industrial customers while simultaneously providing electric power to take advantage of rapid-changing load and market conditions. As previously noted, the three natural-gas/blast furnace gas boilers provide steam to nearby industrial customers. Steam from the combined cycle unit can also provide steam to these same industrial customers. There are long-term symbiotic agreements in place that benefit all parties. Steam not sold to the industrial customers is used to generate electric power to be sold into the MISO market. As explained below, and in the direct testimony of Company witness Troyer, in addition to the steam agreement, the DIG, Kalamazoo, and Livingston plants also are obligated to provide supply for existing commodity sales contracts for energy and capacity which Consumers Energy will assume as part of the purchase of the plants.

The DIG plant has three General Electric ("GE") "F" class gas turbines with two of the turbines operating in a combined cycle mode with a single steam turbine. The steam boilers are primarily fired with blast furnace gas but can also be fired using natural gas as a supplement to the blast furnace gas. The natural gas supplied to the gas turbines and boiler is provided through an interconnect agreement with DTE Gas Company. The gas turbines and boilers do not fire fuels other than natural gas or blast furnace gas. Additional details regarding the arrangements for the DIG Plant can be found in Company witness Galloway's direct testimony. The GE 7F turbine designs are among the most common in the power industry and have a long-proven track record with approximately 950 units put into operation since 1990. The GE gas turbines were recently upgraded to produce more electrical power at a higher efficiency so the simple cycle gas turbine has a nominal heat rate of 10,300 Btu/kWh while the combined cycle unit has a heat rate of approximately 7,200 Btu/kWh. Finally, the DIG Plant's availability has averaged above 90% for the past three years.

Q. Please describe the design of the Kalamazoo Plant.

A. The Kalamazoo Plant was designed to serve as a merchant simple cycle unit primarily providing electric output and volt-amp reactance ("VAR") support playing a critical role in maintaining stability of the MISO grid. The Kalamazoo Plant has one GE "E" class gas turbine operating in a simple cycle mode. Natural gas is provided to the gas turbine through an interconnect agreement with Panhandle Eastern Pipe Line Company, LP. The gas turbine fires only natural gas. Additional details regarding the fuel arrangements for the

Kalamazoo Plant can be found in Company witness Gallaway’ s direct testimony. The GE 7E turbine designs are frequently employed across the United States with 40 states having at least one 7E unit installed. The GE gas turbine has a nominal heat rate of 12,500 Btu/kWh with an average availability above 92% for the past three years.

Q. Please describe the design of the Livingston Plant.

A. The Livingston Plant was designed to serve as a merchant simple cycle unit primarily providing quick-start electric output and VAR support playing a critical role in maintaining stability of the MISO grid. The Livingston Plant has four Pratt and Whitney FT4 gas turbines operating in a simple cycle mode. Natural gas is provided to the gas turbine through an interconnect agreement with DTE Gas Company. The gas turbine does not fire fuels other than natural gas. Additional details regarding the fuel arrangements for the Livingston Plant can be found in Company witness Galloway’s direct testimony. The Pratt and Whitney turbine designs are aero-derivative units converted for power production in the 1960’s with reliability proven by the United States military. The Pratt and Whitney gas turbines have a nominal heat rate of 16,000 Btu/kWh and collectively have an availability factor that has averaged above 96% for the past three years.

Q. What are the expected typical annual costs associated with operating with the DIG, Kalamazoo, and Livingston plants including fuel, O&M, and environmental compliance?

A. The projected annual costs to operate with the DIG, Kalamazoo, and Livingston plants are primarily addressed by Company witnesses Walz and Kapala. In addition, Company witness Kvoriak addresses projected property taxes and Company witness Breining addresses environmental compliance.

Q. How are emissions controlled for the DIG, Kalamazoo, and Livingston plants?

A. The emissions from the DIG, Kalamazoo, and Livingston plants are controlled within the approved air permits by use of low nitrogen oxide combustors, water injection, and tuning the gas turbine combustion process. Carbon dioxide emissions from a natural gas-fired unit are typically much lower than that from the Campbell coal-fired units and even lower than that those from Karn Units 3 and 4, so an overall reduction in carbon dioxide is expected. Company witness Breining presents additional detail on the emissions outlook of the PCA, which includes the purchase of the DIG, Kalamazoo, and Livingston plants in 2025.

Q. What is the schedule for obtaining the necessary environmental permits to operate the DIG, Kalamazoo, and Livingston plants?

A. As explained by Company witness Breining, the Company would not be required to obtain any additional air and/or water permits due to the purchase of the DIG, Kalamazoo, and Livingston plants. The existing permits of the DIG, Kalamazoo, and Livingston plants would simply need an administrative change transferring them into the Company's name. The Company will comply with all permits currently in place.

Q. Please explain the transaction costs that the Company has or expects to incur as a result of the purchase of the DIG, Kalamazoo, and Livingston plants.

A. The transaction costs that the Company has or expects to incur as a result of the purchase of the DIG, Kalamazoo, and Livingston plants include title insurance, transfer tax, survey, legal, and miscellaneous due diligent costs. These costs in the amount of $5 million represent investment costs that the Company will reasonably and prudently incur as a result of the acquisition of these plants.

Q. Please explain the commodity sales contracts held by the DIG, Kalamazoo, and Livingston plants.

A. As explained by Company witness Troyer, the evaluation of CMS Enterprises' bid proposal took into account existing commodity sales contracts attributable to the DIG, Kalamazoo, and Livingston plants. Therefore, the purchase price of the plants appropriately reflects the commodity contracts and the value that those contracts hold. The DIG Plant has existing contracts in place for the provision of steam for AK Steel and Ford Rouge, which are located on the same industrial site as the DIG Plant. The DIG, Kalamazoo, and Livingston plants also have contractual commitments for the sale of energy and capacity, which Consumers Energy will assume upon acquisition of these plants. Company witness Troyer discusses the aforementioned contracts and how the Company intends to address the revenues received pursuant to the contracts.

Q. Has the purchase agreement for the DIG, Kalamazoo, and Livingston plants been signed by the parties?

A. Yes. The contract for the purchase of the DIG, Kalamazoo, and Livingston plants was signed by the parties in June 2021. The contract represents a PSA which will allow the Company to take full ownership of the DIG, Kalamazoo, and Livingston plants on or about May 2025. The DIG, Kalamazoo, and Livingston PSA has been included as Exhibit A-44 (JEB-4).

Q. How do the commodity sales contracts impact the total purchase costs for the DIG, Kalamazoo, and Livingston plants?

A. The PSA for the DIG, Kalamazoo, and Livingston plants, provided as Exhibit A-44 (JEB-4), provides for a Base Purchase Price of $515 million, not including the $5 million in transaction costs identified above. The Base Purchase Price is based on the capacity of the DIG, Kalamazoo, and Livingston plants recognized by MISO for the applicable planning period and made available by CMS Enterprises for sale to Consumers Energy for the applicable Planning Years as set forth in the chart below. These capacity amounts of the DIG, Kalamazoo, and Livingston plants reflect CMS Enterprises' existing commitments for the provision of capacity from the DIG, Kalamazoo, and Livingston plants to third parties. The chart below shows the amount of uncommitted capacity from these plants as of the time the PSA was executed:

Planning Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Capacity (ZRC)	358	482	480	596	688	739	739	789	800	800	828	828	828	828	828

Prior to the closing of the sale of the DIG, Kalamazoo, and Livingston plants, CMS Enterprises may sell an additional 45 Zonal Resource Credits, each year, for MISO Planning Years 2027 through 2039 (June 1, 2027 through May 31, 2040). The PSA contains a formula to reduce the Purchase Price if these additional sales occur. The revenues for these sales will be for the benefit of Consumers Energy after closing.

The PSA further provides that, should CMS Enterprises reacquire some or all of the capacity that was sold to third parties, up to the amounts shown in the chart below, (reacquired capacity amounts no more than those amounts sold by year), by the closing of the sale of the plants, then the total purchase price of the DIG, Kalamazoo, and Livingston plants will be increased to up to $525 million (based on a formula set forth in the PSA), as long as the reacquired capacity is fully available to Consumers Energy at the time of the closing of the sale of the plants.

Planning Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Capacity (ZRC)	93	97	99	23	23	28	28	28	28	28	0	0	0	0	0

Since the purchase price of the DIG, Kalamazoo, and Livingston plants will be up to $525 million, the Company is assuming total purchase costs of $530 million for the DIG, Kalamazoo, and Livingston plants, inclusive of transaction costs, in this proceeding.

Q. Has the Company's Board of Directors approved the purchase of the DIG, Kalamazoo, and Livingston plants?

A. Yes. The CMS Energy Board of Directors approved the purchase of the DIG, Kalamazoo, and Livingston plants on June 11, 2021.

Q. Is the Company requesting cost pre-approval of the purchase price of the DIG, Kalamazoo, and Livingston plants in this IRP proceeding?

A. Yes. As explained by Company witness Blumenstock, the Company is proposing to purchase the DIG, Kalamazoo, and Livingston plants as part of the PCA proposed in this case. Since the Company will incur the cost to purchase the DIG, Kalamazoo, and Livingston plants within three years after the Commission's expected order approving this IRP, the Company requests that the Commission specifically approve the acquisition and total purchase costs of $530 million, which is inclusive of transaction costs, as reasonable and prudent for cost recovery purposes pursuant to MCL 460.6t(11) and all other applicable law. With the approval of these costs by the Commission, in accordance with MCL 460.6t(17), the Company will include in retail rates all reasonable and prudent costs specifically approved pursuant to MCL 460.6t(11) that have been incurred to implement the approved IRP, and specifically the purchase of the DIG, Kalamazoo, and Livingston plants. Therefore, if the Company does not ultimately incur the full $530 million in identified purchase costs for the DIG, Kalamazoo, and Livingston plants, the Company will only include the amounts in retail rates that it actually incurs.

Q. Does this conclude your direct testimony?

A. Yes.

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 Approval of an Integrated Resource Plan	)	Case No. U-21090
under MCL 460.6t, certain accounting	)	
approvals, and for other relief.	)	
______________________________________	)	

DIRECT TESTIMONY

OF

KEITH G. TROYER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

Q. Please state your name and business address.

A. My name is Keith G. Troyer, 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. In what capacity are you employed?

A. I am the Director of Electric Grid Integration Contracts and Settlements in the Electric Supply Section of the Electric Grid Integration Department.

QUALIFICATIONS

Q. Please describe your educational background and work experience.

A. I received the degree of Bachelor of Science in Engineering with a specialty in Civil Engineering from Michigan State University in 2008. In 2015, I became a Registered Professional Engineer in the state of Michigan. In 2018, I received a Master of Business Administration ("MBA") through Michigan State University's Executive MBA Program.

In July 2009, I joined Consumers Energy as an Electric System Owner. In January 2011, I accepted a position as an Engineer in the Transactions and Resource Planning Section of the Energy Supply Department. In that role, I was responsible for administration and coordination of the Company's Experimental Advanced Renewable Program ("EARP") – Solar, part of the Company's Renewable Energy Plan ("RE Plan"). I was involved in the development and implementation of the EARP-Solar expansion in 2011. In June 2013, I began taking on additional responsibilities associated with the RE Plan, including the calculation of the Transfer Price associated with renewable energy and capacity and the tracking of Renewable Energy Credits ("RECs"). In 2014, I was also responsible for supervision of the implementation of the EARP-Anaerobic Digestion pilot. In December 2016, I transitioned to a new role where my supervisory and direct responsibilities included administering Power Purchase Agreements ("PPAs"), issuing solicitations for energy and capacity, and managing the Company's capacity position with Midcontinent Independent System Operator, Inc. ("MISO"). In September 2019, I became the Director of Electric Grid Integration Contracts and Settlements.

Q. What are your responsibilities as Director of Electric Grid Integration Contracts and Settlements?

A. My responsibilities include oversight of the Company's distribution agreements and programs, PPAs, solicitations for energy and capacity, renewable energy compliance, and electric wholesale settlement activities.

Q. Have you previously provided testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I provided testimony in:

- MPSC Case No. U-17095-R (direct), the Company's 2013 Power Supply Cost Recovery ("PSCR") Reconciliation Case, regarding 2013 RE Plan expenses recovered through PSCR;
- MPSC Case No. U-17631 (direct), the Company's 2013 RE Reconciliation Case, regarding 2013 RE Plan expenses recovered through PSCR, RE compliance, and new renewable capacity compliance;
- MPSC Case No. U-17317-R (direct), the Company's 2014 PSCR Reconciliation Case, regarding 2014 RE Plan expenses recovered through PSCR;
- MPSC Case No. U-17792 (direct and rebuttal), the 2015 biennial review of the Company's RE Plan, regarding RE Plan expenses recovered through the PSCR, RE compliance, new renewable capacity compliance, and RE programs;
- MPSC Case No. U-17803 (direct), the Company's 2014 Renewable Cost Reconciliation Case, regarding 2014 RE Plan expenses recovered through PSCR, RE compliance, and new renewable capacity compliance;

- MPSC Case No. U-17678-R (direct), the Company's 2015 PSCR Reconciliation Case, regarding 2015 RE Plan expenses recovered through PSCR;
- MPSC Case No. U-17918 (rebuttal), the Company's 2016 PSCR Plan and five-year forecast, regarding the impacts of net electric metering on energy supply;
- MPSC Case No. U-18081 (direct and revised), the Company's 2015 Renewable Reconciliation case, regarding 2015 RE Plan expenses recovered through PSCR, RE compliance, and new renewable capacity compliance;
- MPSC Case No. U-18090 (direct, rebuttal, reopened rebuttal, and second reopened rebuttal, and affidavit), the Company's 2016 Public Utility Regulatory Policies Act of 1978 ("PURPA") case to establish a method and calculation for avoided costs;
- MPSC Case No. U-17918-R (direct), the Company's 2016 PSCR Reconciliation Case, regarding 2016 RE Plan expenses recovered through PSCR;
- MPSC Case No. U-18241 (direct), the Company's 2016 RE Cost Reconciliation Case, regarding 2016 RE Plan expenses recovered through PSCR;
- MPSC Case No. U-18402 (direct and rebuttal), the Company's 2018 PSCR Plan and five-year forecast, regarding long-term PPAs and capacity forecast;
- MPSC Case No. U-18231 (direct and rebuttal), the 2017 biennial review of the Company's RE Plan, regarding the Company's Request for Proposal process for new resources, the cost of new RE resources included in the RE Plan, and the risks that may drive performance to vary, associated with these topics;
- MPSC Case No. U-18351 (rebuttal), the Company's 2017 Application to comply with Section 61 of 2016 PA 342, regarding customer credits in voluntary RE programs and competitive solicitations;
- MPSC Case No. U-20165 (direct, rebuttal, and second rebuttal), the Company's 2018 Integrated Resource Plan ("IRP"), regarding long-term PPAs, proposed changes to the Company's PURPA avoided cost implementation, the Company's proposal to utilize competitive solicitations and the implementation of the Financial Compensation Mechanism ("FCM");
- MPSC Case No. U-20219 (direct and rebuttal), the Company's 2019 PSCR Plan and five-year forecast, regarding long term PPAs and MISO revenue and expenses;

- MPSC Case No. U-20202 (direct), the Company's 2018 PSCR Reconciliation Case, regarding purchased power supply costs and the allocation of costs to the renewable resource fund.;

- MPSC Case No. U-20469 (affidavit), the Company's Application requesting an Order Rescinding Avoided Cost Rates, regarding the Company's avoided costs, obligations to enter new PPAs, and establishment of new avoided costs in the Company's IRP;

- MPSC Case No. U-20496 (direct), the Company's Application for approval of Amendments to the PPA with Viking Energy of Lincoln, LLC, Viking Energy of McBain, LLC, and Hillman Power Company;

- MPSC Case No. U-20604 (direct), the Company's Application for approval of PPAs;

- MPSC Case No. U-15805-S (affidavit), the Company's Application for approval of a renewable energy purchase agreement with River Fork Solar, LLC.

- MPSC Case No. U-20525 (direct and rebuttal), the Company's 2020 PSCR Plan and five-year forecast, regarding long-term PPAs and the treatment of MISO revenue and expenses;

- MPSC Case No. U-20697 (direct and rebuttal), the Company's 2020 electric rate case, regarding PSCR expenses, transmission cost analysis, state reliability mechanism methodology, and IRP supply implementation activities;

- MPSC Case No. U-20220 (direct), the Company's 2019 PSCR Reconciliation Case, regarding purchased power supply costs and the allocation of costs to the renewable resource fund;

- MPSC Case No. U-15805-T (affidavit), the Company's Application for approval of amended renewable energy and PPAs with North American - Central LLC;

- MPSC Case No. U-20833 (direct), the Company's Application for approval of PPAs with STS Hydropower LLC;

- MPSC Case No. U-20838 (direct), the Company's Application for approval of new PPAs with members of the Independent Power Producers Coalition of Michigan;

- MPSC Case No. U-20734 (direct), the Company's Application for approval of an amendment to the PPA with Entergy Nuclear Power Marketing, LLC; and

- MPSC Case No. U-20896 (direct), the Company's Application for approval of an amendment to the PPA with Midland Cogeneration Venture Limited Partnership.

PURPOSE OF DIRECT TESTIMONY

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to:

- Provide an overview of the key input assumptions in this IRP related to the Company's existing and anticipated PPAs;
- Provide an overview of the MPSC Staff's ("Staff") Customer Distributed Generation ("DG") Program proposal, as included in the 2018 IRP Settlement Agreement approved in Case No. U-20165, and discuss the Company's consideration of that proposal;
- Detail the proposed changes to the Company's Financial Compensation Mechanism ("FCM");
- Provide an overview of the Company's implementation of PURPA avoided costs and detail the proposed changes to the Company's PURPA avoided cost implementation;
- Provide an overview of the Company's IRP-based competitive solicitations and detail the proposed changes to the Company's IRP-based competitive solicitations;
- Provide an overview of the Company's research on best practices for competitive procurement of renewable PPAs; and
- Provide an overview of the Company's 2021 Natural Gas Plant Request for Proposals ("RFP").

Q. How is the remainder of your direct testimony organized?

A. First, I provide a summary of the existing PPAs that have been executed by the Company and approved by the Commission. Then, I will discuss the assumptions related to: (i) the expected commercial operation date and execution of new PURPA-based contracts; (ii) the assumed PPA additions resulting from the annual IRP competitive solicitations issued in 2019 through 2021 to meet the Proposed Course of Action ("PCA") approved in the 2018

IRP Settlement Agreement, for commercial operation dates in 2022 through 2024; and (iii) the treatment of PPAs with contract expirations that occur during a MISO Planning Year.[1] Then, I will provide an overview of Staff's Customer DG Program proposal, as included in the 2018 IRP Settlement Agreement approved in Case No. U-20165 ("IRP Settlement Agreement"), and discuss the Company's consideration of that proposal. Next, I will provide an overview of the Company's proposed changes to the applicability and implementation of the FCM for new PPAs. Then, I will provide a summary of the Company's most recent avoided cost proceeding including the methodology and implementation procedures approved by the Commission. Next, I will discuss proposed changes to the avoided cost methodology and implementation procedures to better align with the Company's long-term capacity needs included in this IRP. Then, I will provide a summary of the Company's competitive procurement process for IRP-based supply-side resources including: (i) an overview of the solicitations issued in accordance with the IRP Settlement Agreement; (ii) proposed updates, clarifications, and enhancements for future IRP-based competitive solicitations; and (iii) the role of the Independent Administrator for future IRP-based competitive solicitations. Next, I will discuss the research conducted by the Company's consultant on best practices for the competitive procurement of renewable PPAs. Lastly, I will discuss the 2021 Natural Gas Plant RFP issued by the Company in January 2021 to support this IRP filing.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

[1] MISO defines a Planning Year as the 12-month period beginning June 1 of one year and concluding May 31 of the following year.

Exhibit A-45 (KGT-1)	Purchase Power Contract Rates and MPSC Approval Orders;
Exhibit A-46 (KGT-2)	Procurement Trends and Potential Strategies for Renewable PPAs;
Exhibit A-47 (KGT-3)	U-20697 Embedded Capacity Costs - $/Peak kW Sales;
Exhibit A-48 (KGT-4)	Report of the Independent Administrator dated March 18, 2020; and
Exhibit A-49 (KGT-5)	Charles River Associates, Inc. ("CRA") Recommendation Letter.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

SECTION I: KEY INPUTS ASSUMPTIONS RELATED TO PPAs

Q. Are you familiar with the Company's PPAs for energy and capacity?

A. Yes. As the Director of the Electric Grid Integration Contracts and Settlements at Consumers Energy, I am responsible for oversight of negotiation, execution, and administration of the Company's PPAs.

Q. Please summarize how the Company's PPAs are included in the modeling assumptions for this proceeding.

A. The Company has or expects to have 125 long-term PPAs (including proxy assumptions) in place representing 4,107 MW of contract capacity with independent power producers for the purchase of energy, capacity, and/or RECs. Of the 125 PPAs the Company has in place, 100 PPAs are for the purchase of energy and capacity, 3 PPAs provide renewable energy under the Renewable Resource Program (a.k.a. Green Generation Program), 11 PPAs provide renewable energy under the RE Plan, and 3 PPAs are in place under the EARP-Anaerobic Digestion Program. Additionally, the Company has executed 8 contracts for the purchase of energy and has 379 contracts in place for the purchase of solar energy, capacity, and RECs as part of the EARP-Solar Program.

Q. Please explain Exhibit A-45 (KGT-1).

A. Exhibit A-45 (KGT-1) is a list of the contracts that the Company currently has or expects to have in place as a base modeling assumption during the IRP study period. Exhibit A-45 (KGT-1), column (a), lists the current counterparties with which the Company has previously executed a contract. Column (b) shows the amount of contract capacity that the Company purchases under each contract. Column (c) shows the fuel used to generate electricity under the PPA. Column (d) shows the Commission order that approved each PPA. Column (e) shows the expected termination date specified for each PPA. Column (f) shows the entities up to the size of the Company's PURPA purchase obligation threshold (currently 20 MW in size) that the Company anticipates will enter into new PURPA contracts with the Company upon termination of their current PPAs.

Q. What assumptions are included in the IRP modeling for PPAs?

A. The expected production and associated expense from the PPAs are included as part of the Company's supply portfolio through the expected termination of the agreements shown in Exhibit A-45 (KGT-1), column (d). The Company forecasts that at the conclusion of their existing PPAs, the counterparties with renewable generators that have contracts for energy and capacity, as part of the Renewable Resource Program, or as part of the Company's Renewable Energy Plan shown on Exhibit A-45 (KGT-1), up to 20 MW in size will sign new PURPA contracts with the Company at rates similar to the PPA with River Fork Solar. These facilities are identified in column (f).

Q. Are there any bilateral purchase agreements for energy or capacity included in this IRP?

A. No.

Q. Are there any PPAs included in this IRP that have not been previously approved by the Commission?

A. Yes. The Commission's September 11, 2019 Order in Case No. U-20615 approved a settlement agreement between the Company and various developers to resolve outstanding rights and claims to new PURPA PPAs ("PURPA Settlement Agreement"). The PURPA Settlement Agreement resulted in the execution of 170 MW of PURPA PPAs in the Company's PURPA queue at the full PURPA avoided cost from Case No. U-18090, which is 20 MW more than the amount included in the Company's 2018 IRP in Case No. U-20165. Additionally, the PURPA Settlement Agreement resulted in the award of 414 MW of PURPA PPA entitlements at the Company's reduced avoided cost from Case No. U-18090. In accordance with the PURPA Settlement Agreement, qualifying facilities ("QFs") that have entered into a PPA as a result of the 414 MW of entitlement, are permitted to terminate and replace executed PPAs with new PPAs that meet the requirements of the PURPA Settlement Agreement. The process of terminating and replacing PPAs causes some ambiguity in the modeling assumptions used in the preparation of this IRP. Thus, the Company has assumed that the PPAs included in the 584 MW of capacity in the PURPA Settlement Agreement will begin commercial operation on the Expected Start Date included in each PPA as was known on June 1, 2020. All of the PPAs executed as part of the 584 MW utilize solar photovoltaic technology for generation. These contracts are included in Exhibit A-45 (KGT-1), rows 1 through 96.

The Company has executed only 574 MW of the total 584 MW of PURPA capacity and has therefore included a proxy PPA shown as the PURPA Aggregate on row 97 of Exhibit A-45 (KGT-1). Additionally, Exhibit A-45 (KGT-1) shows placeholders for the new PPAs that it expects to enter into as a result of the IRP Settlement Agreement from the 2019 through 2021 solar competitive solicitations for facilities that are expected to begin commercial operation in 2022 through 2024.

Q. How has the Company included the new IRP PCA PPAs in this filing?

A. Similar to the treatment of PURPA PPAs, the Company locked in assumptions regarding the new IRP PCA PPAs on June 1, 2020. At that time, the Company had not yet executed any PPAs as a result of the 2019 or later solicitations.[2] The IRP Settlement Agreement requires at least 50% of new solar capacity to come from PPAs in each annual solicitation. Therefore, the Company has assumed June 1st start dates for half of the solicitation capacity through new solar PPAs beginning operation in 2022 through 2024 as shown in Exhibit A-45 (KGT-1), rows 98 through 100.

Q. How are the PPAs represented in this filing with respect to their capacity contribution towards the Company's planning reserve margin requirements from MISO?

A. MISO requires the Company to fulfill its capacity needs for the entire Planning Year which begins June 1st and ends May 31st. If a contract for energy and capacity or as part of the Renewable Resource Program terminates before the end of the Planning Year, it does not fulfill MISO's requirements and is not included as a capacity resource for the Planning

[2] The Commission's April 8, 2021 Order in Case No. U-20165 approved the 140 MW PPA with Calhoun Solar Energy, LLC from the 2019 IRP competitive solicitation. 10 MW from the 2019 competitive solicitation has been made available to PURPA QFs at the avoided cost set in accordance with the IRP Settlement Agreement from the 2019 solicitation results.

Year.[3] For example, prior to the recent amendment, the Company's PPA with the Palisades Nuclear Plant ended on April 11th, 2022, which occurred during the Planning Year that began June 1, 2021.[4] Since the PPA did not continue through May 31, 2022, the capacity would not be included in the forecast of Company resources for Planning Year 2021/2022 (i.e. Planning Year 2021). The amount of capacity expected to be supplied by each PPA, as well as the 10 MW of new PURPA solar PPA(s) and the 550 MW of new IRP PPA solar from the 2019 through 2021 solicitations, is shown on Exhibit A-6 (STW-3), sponsored by Company witness Sara T. Walz.

Q. Does the Company have any generation in its supply portfolio sourced from nuclear technology?

A. Yes. While the Company does not own any nuclear fueled generation, it has an existing PPA with Entergy Nuclear Power Marketing, LLC for the output of the Palisades Nuclear Plant. The PPA was most recently amended on January 28, 2020 to extend the termination of the PPA from April 11, 2022 to May 31, 2022. This amendment was approved by the Commission's August 20, 2020 Order Approving a Settlement Agreement in Case No. U-20734.

SECTION II: Staff's Customer DG Program Proposal

Q. Are you familiar with the IRP Settlement Agreement provision related to DG?

A. Yes. As part of the IRP Settlement Agreement, the Company agreed that its next IRP would include consideration of a DG program, similar to Staff's Customer DG Program proposed by Staff witness Meredith A. Hadala in her direct testimony in Case No. U-20165.

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[3] The Company has included the entire capacity from the MCV PPA through Planning Year 2029/2030.

[4] As discussed below, the Commission recently approved an amendment to the Palisades Nuclear Plant PPA which extended the term through May 31, 2022 and will allow the Company to rely on the capacity provided by the PPA for the entire 2021 MISO Planning Year. See Case No. U-20734.

Q. What was the underlying objective of the IRP settlement provision?

A. A key objective of including this provision in the settlement agreement was to facilitate increased access to customer rooftop solar. In Case No. U-20165, Staff proposed that "…2% of the capacity planned to be acquired in every competitive solicitation be reserved for a Customer Distributed Generation program."

Q. What actions has the Company taken regarding DG since the IRP Settlement Agreement?

A. Since the IRP Settlement Agreement, the Company has taken steps to expand customer access to distributed generation. On November 19, 2020, the Company reached its statutory cap of 1% on Category 1 and Category 2 distributed generation.[5] In an effort to expand customer access to rooftop solar until an alternative compensation methodology is established, the Company voluntarily doubled its distributed generation program's cap to 2% of average peak load on January 1, 2021. See MPSC Case No. U-20697, December 17, 2020 Order, page 310.

Q. Why did the Company voluntarily increase the size of its DG program?

A. The Company's decision to voluntarily double its DG program showcases the Company's support for customers who wish to install rooftop solar generation. The Company continues to advocate for DG policy provisions that prioritize the needs of all customers in Michigan, recognizing that the expansion of the cap is a simple, albeit temporary solution. Solar plays an important role in the Company's Clean Energy Plan, and the Company fully supports continuing to develop clean energy in Michigan. Voluntarily increasing the 1% statutory DG cap to 2% ensures that customers have expanded access to rooftop solar.

[5] See the Company's November 19, 2020 filing in Case No. U-15787.

Q. Does this voluntarily expansion of the Company's DG program address the objectives of the IRP's settlement provisions?

A. Yes. The voluntary expansion of the Company's DG tariff achieves the goal of facilitating increased customer access to rooftop solar.

Q. Has the Company considered Staff's Customer DG Program proposed in Case No. U-20165?

A. Yes. The Company has considered Staff's proposal and believes that it is unnecessary due to the voluntary expansion of the Company's DG tariff.

<u>SECTION III: FCM IMPLEMENTATION</u>

Q. Are you familiar with the Company's FCM?

A. Yes, I sponsored testimony in the Company's 2018 IRP and 2021 Electric Rate case, Case No. U-20697, related to the implementation of the FCM on new PPAs.

Q. Is the Company proposing to make any changes to the implementation of the FCM?

A. Yes. The Company is proposing two changes to the implementation of the FCM. First, the IRP Settlement Agreement establishes an annual cap on the maximum PPA rate that is eligible for FCM. The Company proposes to remove the FCM cap for several reasons. The FCM cap is based on a $/MWh limit which does not align with the Company's current compensation structure in PPAs which include a capacity payment based on $/ZRC-day or $/ZRC-month, and an energy payment based on $/MWh. Because of this disconnect in cap and compensation structure, the Company is limited in the amount of FCM it is able to recover for PPAs. For example, if the Company only procures ZRCs and/or RECs and not the associated energy, it would be prohibited from collecting any FCM on the PPA. Similarly, the FCM cap unfairly restricts the Company's ability to recover an appropriate amount of FCM on dispatchable resources, where the energy production may be significantly reduced in order to improve the PPAs responsiveness to energy market signals.

Second, the FCM is currently applicable to only new PPAs that are not included in the Company's RE Plan. This limitation disincentivizes the pursuit of PPAs, in lieu of Company-owned generation, as part of the RE Plan. Additionally, the Company is not able to apply the FCM to PPA amendments which disincentivizes the pursuit of contract extensions through bilateral negotiations. For example, if the Company wishes to delay the construction of a new generator by negotiating a 10-year extension on a PPA, it would not be permitted to receive an FCM on the PPA to delay the new generator even though the PPA would be substantially replacing the new generation resource. Rather, in this example, the Company would be incentivized to sign a new 10-year PPA or construct the new generation resource, both potentially at a higher cost, than the existing PPA that is available for consideration. For these reasons, the Company proposes that the FCM be applicable to all new PPAs, including RE Plan PPAs, as well as all PPA amendments, except affiliate PPAs which are prohibited by law.

SECTION IV: IMPLEMENTATION OF PURPA AVOIDED COSTS

Q. Are you familiar with the Company's implementation of PURPA avoided costs in accordance with the IRP Settlement Agreement?

A. Yes. I sponsored testimony related to the Company's PURPA avoided cost construct in Case No. U-18090 and the Company's 2018 IRP. Most recently, I submitted testimony, exhibits, and an affidavit to reset the PURPA full avoided cost rate in Case No. U-20165 in accordance with the IRP Settlement Agreement. I have management oversight of the administration of all PPAs and distribution agreements, as well as monthly settlements with MISO and QFs.

Q. What are avoided costs?

A. This term comes from the Federal Energy Regulatory Commission ("FERC") rules established and embodied in the Code of Federal Regulations, where "avoided costs" are defined as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."

Q. What is a QF?

A. A QF can be either a qualifying small power production facility or a qualifying cogeneration facility that meets certain size, fuel, and/or efficiency standards.

Q. Are QFs required to sell their energy and/or capacity at avoided costs?

A. No. These generating facilities can enter into negotiated PPAs with the Company or others or to submit bids in response to RFPs issued by the Company or others that seek to acquire energy and/or capacity.

Q. Do QFs have an obligation to execute contracts with the Company?

A. No. QFs have the option to enter into PURPA contracts with the Company but may also participate in the wholesale market or sell to other utilities at negotiated rates.

Q. Does the Company have an obligation to execute PURPA contracts with QFs?

A. Yes. The Company generally has an obligation to enter into contracts for energy and capacity up to its purchase obligation threshold (currently 20 MW in size[6]) with QFs that

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[6] On June 14, 2021, the Company filed an application with FERC to reduce the must buy obligation threshold to 5 MW for qualifying small power production facilities in accordance with FERC Order 872. The FERC application does not apply to qualifying cogeneration facilities.

both (i) are capable of delivering energy and capacity to the Company and (ii) do not have nondiscriminatory access to wholesale markets. Throughout my direct testimony, when discussing QFs, I am referring to facilities up to the size of the Company's must buy obligation threshold that meet the requirements to be certified as a QF, unless otherwise noted.

Q. Please describe the Company's currently approved PURPA avoided cost construct.

A. On May 26, 2021, the Commission issued an Order in Case No. U-20165 approving new PURPA full avoided cost rates, including updates to the Standard Offer Tariff and associated Standard Offer Contract that were updated in accordance with the IRP Settlement Agreement. Under this existing construct, the Standard Offer Tariff and Standard Offer Contract are available for QFs up to 2 MW in size. In accordance with the IRP Settlement Agreement, "the full avoided cost rate offered will be equal to the highest priced proposal that received a contract in the competitive solicitation and the contract length will be the same as offered in the competitive solicitation."

The Company currently offers both full avoided costs and reduced avoided costs rates for PURPA QFs. The current reduced avoided cost rate is based on the MISO Planning Resource Auction ("PRA") capacity rate, adjusted annually, and either (i) a 10-year term based on the forecast of LMPs for the first five years and year six through year 10 equal to the energy price in the fifth year of the LMP forecast, or (ii) actual LMPs for 15 years. Regardless of whether a PURPA contract is based on full avoided cost or reduced avoided cost, QFs that enter into a PPA are not required to transfer RECs to the Company, but the QF and Company can negotiate a separate agreement for the RECs at a mutually agreed upon price.

Q. Please explain the circumstances in which a QF is currently eligible to receive full avoided cost rates.

A. While the Company is proposing several prospective changes to its PURPA avoided cost construct as further detailed below, there are several methods by which a QF can *currently* pursue contracts with the Company:

1. Any QF up to the Company's must buy obligation threshold can participate in the Company's competitive solicitations, regardless of the technology specified, and receive the rate[7] included in their proposal, if selected;
2. Any remaining capacity solicited but not filled through each solicitation is made available to QFs on a first-come, first-served basis at the full avoided cost rates based on that solicitation;
3. Any QF with an existing PPA as of January 1, 2019 with an expiring full avoided cost PURPA PPA for energy and capacity is eligible to receive the most recently Commission-approved full avoided cost rate for a new PPA; and
4. QFs up to 150 kW that request the Standard Offer Contract will receive the most recently Commission-approved full avoided cost rates.

Q. Is the Company proposing to make any changes to its currently approved PURPA avoided cost construct?

A. Yes. There are several adjustments to the current PURPA avoided cost review and implementation that should be adopted.

Q. What changes does the Company propose to make to its review of PURPA avoided costs?

A. The Company requests that the Commission clarify that the required review of the Company's PURPA avoided cost construct is adequately met through the IRP filings that

[7] QFs participating in the solicitation are treated as other respondents to the solicitation which requires meeting the eligibility requirements of the solicitation and will result in the transfer of RECs, if applicable, to the Company under the solicitation-based PPA.

the Company has agreed to file every three years.[8] Previously, the Commission's May 31, 2017, Order in Case No. U-18090 required a biennial review of the Company's PURPA avoided costs. See Case No. U-18090, May 31, 2017 Opinion and Order, page 28. This application is being filed approximately 2 years from the approval of the IRP Settlement Agreement, which resulted in the approval of the Company's current PURPA avoided cost construct. Long-term planning, including both PURPA and non-PURPA resources, is most adequately addressed in IRP filings, and the Company intends to continue to update PURPA avoided costs following the conclusion of each annual IRP solar solicitation. As the Company intends to continue filing IRPs every three years to implement the buildout of solar resource additions, the Company requests that the Commission clarify, or in the alternative modify, its previous order in Case No. U-18090 and find that the required review of the Company's PURPA avoided cost construct is adequately met through the IRP filings that the Company has agreed to file every three years.

Q. Has the Commission previously indicated a willingness to examine avoided costs as part of an IRP proceeding?

A. Yes. The Commission's November 21, 2017 Order in Case No. U-18090 states :

> Going forward, the Commission believes that PURPA avoided costs should be integrated with capacity demonstration and IRP proceedings in order to more accurately assess capacity needs. The IRP proceedings are conducive to updating avoided costs, because the Commission will already be evaluating, in detail, utility-specific plans for any incremental generation or purchases along with their associated costs.

The Company views this language as support by the Commission to include both an update to avoided costs and review of the Company's capacity needs in this IRP, and all IRPs

[8] As explained by Company witness Richard T. Blumenstock, the Company's agreement to continue to file IRPs on a three-year basis is conditioned on the approval of the Company's PCA.

going forward. Additionally, it should be noted that, in Case No. U-20905 *et al.*, the Commission indicated that it "will consider in the next biennial review for each utility whether review on a biennial basis or a less frequent review is appropriate." Case No. U-20905 *et al.*, January 21, 2021 Order, page 27.

Q. What changes does the Company propose to make to its implementation of PURPA avoided costs?

A. There are several changes that the Company proposes to make to the implementation of PURPA avoided costs. These changes pertain to eligibility for full avoided cost rates and the Standard Offer.

Q. Please explain the Company's proposed changes to eligibility for full avoided cost rates.

A. As explained above, there are multiple ways in which full avoided costs are *currently* available to QFs. Given the findings in FERC's July 16, 2020 Order, 172 FERC ¶ 61,041 ("FERC Order 872"), and November 19, 2020 Order, 173 FERC ¶ 61,158 ("FERC Order 872-A"), the Company proposes to remove two options from the Company's PURPA full avoided cost construct: (i) eligible QFs up to 150 kW that request the Standard Offer Contract are eligible to receive the most recent Commission-approved full avoided cost rates; and (ii) when there is remaining unfilled capacity from an annual solicitation, the unfilled capacity is made available to QFs on a first-come, first-served basis.

FERC Order 872 explains that when a competitive solicitation process is used to meet a utility's full capacity needs, a utility is not required to enter into PURPA contracts for capacity outside of that competitive solicitation process. FERC Order 872, page 236. FERC further explained that "[t]his approach further shields purchasing electric utilities from situations... where QFs could simply sit out the competitive solicitation process (or participate but not have their bids accepted), but then seek to sell capacity to the purchasing electric utility and to receive a separate higher administratively-determined avoided cost rate including an avoided cost capacity rate, and even potentially displace non-QF competitive solicitation winners." FERC Order 872, page 237. Therefore, since the Company is using a competitive solicitation approach, in which QFs sized 150 kW or less are able to participate, for acquiring the Company's full capacity needs, there is no basis to require the Company to pay full avoided cost rates (which include a capacity component) to QFs 150 kW and below. QFs 150 kW and below would still remain eligible for standard, reduced avoided cost rates like any other QF.

Furthermore, on January 1, 2021, the Company increased the size of its DG Program from 1% to 2% of the Company's peak load as previously discussed to continue providing an opportunity for customers to install solar on their homes and businesses using the Company's well-established program. Additionally, since the Commission's approval of the IRP Settlement Agreement, the Company has neither (i) executed any Standard Offer Contracts with QFs up to 150 kW in size, nor (ii) been contacted by a generator up to 150 kW in size claiming to be a QF or asking for a PURPA-based PPA. It is apparent that customers are not seeking to execute PURPA-based PPAs up to 150 kW in size, but instead are interested and applying for the DG program. For these reasons, QFs up to 150 kW in size should only be eligible to receive full avoided cost rates if they meet the full avoided cost eligibility that all other QFs must meet.

Providing QFs with capacity unfilled by the Company's annual solicitations is also inconsistent with FERC Order 872. The Company is proposing to satisfy its full supply-side capacity needs through its annual solicitations and permits all QFs up to the Company's PURPA purchase obligation threshold to participation in those solicitations. Pursuant to FERC Order 872, since the Company is meeting its full capacity needs in its annual solicitation, the Company's avoided capacity cost is zero and the Company is not required to enter into PURPA contracts for capacity outside of that competitive solicitation process. Therefore, QFs should not be eligible for the Company's full avoided cost rates outside of the Company's annual competitive solicitation process. Moreover, as discussed in more detail below, the Company is proposing greater flexibility in the amount of MWs acquired in each competitive solicitation and a reconciliation process in future IRPs which means that it will not be known on an annual basis if there is open capacity to offer QFs. In other words, under the Company's proposed PCA, the amount of capacity acquired in any one year or any one solicitation would not necessarily be indicative of a capacity need that could or should be filled by PURPA QFs outside of the solicitation process. Instead, the Company's PCA will employ multiple solicitations over multiple years to fill an overall capacity need in a more flexible manner.

Through participation in the annual solicitation process, QFs have an opportunity to secure contracts with the Company by winning the solicitation or may receive standard, reduced avoided cost rates for energy, over a fixed term, consistent with the Company's currently approved methodology for such rates.

While the Company is proposing the above changes to QF eligibility for full avoided cost rates, the Company is not proposing any changes to the eligibility of certain existing QFs with respect to the Company's full avoided cost rates. The IRP Settlement Agreement provided that any QF with an existing PPA as of January 1, 2019 with an expiring full avoided cost PURPA PPA for energy and capacity is eligible to receive the most recently Commission-approved full avoided cost rate for a new PPA. So long as a QF has an existing PPA as of January 1, 2019, the Company agrees to pay those QFs the Company's currently approved full avoided cost rates at the time of PPA expiration. QFs with PPAs entered after January 1, 2019 would need to enter future competitive solicitations to secure contracts with the Company, in accordance with the direction in FERC Order 872.

Q. How should the Company's PURPA capacity needs be determined?

A. Pursuant to the process approved in the IRP Settlement Agreement, and the direction provided by FERC in FERC Order 872, the Company has no PURPA capacity need so long as the Company is implementing a competitive biddings process to acquire its full capacity needs. Since the Company's PCA presents the capacity needs of the Company, the Company requests a finding from the Commission in this proceeding that the Company has no capacity need so long as the Company is implementing the PCA, including the competitive bidding process for all future capacity needs.

Q. Please explain the Company's proposed change to the eligibility for the Standard Offer.

A. Currently, QFs up to 2 MW in size are eligible for the Company's Standard Offer PPA. The Company proposes to reduce the size of the Standard Offer Contract and Standard Offer Tariff to 100 kW. There are numerous reasons for this proposal. First, 18 CFR 292.304(c) requires utilities to implement a Standard Offer Program for QFs up to 100 kW in size, making the Company's proposal consistent with FERC's PURPA regulations. Second, Standard Offer Tariff rates are most appropriate for small developers and customers that lack the experience and resources needed for larger forays into the electricity generation business. The current Standard Offer Tariff size extends to developers who have significant experience and resources, and who do not need to have their contracting facilitated through a Standard Offer Tariff. The majority of requests for Standard Offer PPAs come from large sophisticated solar project developers and, based on the Company's experience, these developers have or are in the process of developing larger solar projects at or above 5 MW. For instance, the PURPA Settlement Agreement in Case No. U-20615 resulted in the execution of 22 PPAs with QFs up to 2 MW in size and 21 of those PPAs are under development with a subsidiary or an affiliate of a sophisticated solar development company.[9] Third, FERC Order 2222 requires that MISO develop a process by which distributed energy resources 100 kW and larger can participate in the wholesale market. Since distributed energy resources 100 kW and larger can participate in the wholesale market, providing the Standard Offer to facilities over 100 kW is unnecessary.

Q. Is the Company's proposed change to the eligibility for the Standard Offer consistent with the MPSC's previous direction?

A. Yes. In Case No. U-20905 *et al.*, the Commission found the following with respect to the Standard Offer cap:

> …should a utility receive authorization from FERC to terminate its obligation to purchase from QFs above 5 MW, the Commission directs the utility, in its next avoided cost review that follows the termination, to explain and support its position on the standard offer cap. Should a utility not propose a standard offer cap being set at 5 MW, it should provide a rationale as to why such a standard offer cap is not appropriate. [Case No. U-20905 *et al.*, January 21, 2021 Order, page 26.]

[9] Three projects are associated with NextSun Energy LLC. Three projects are associated with Inman Solar LLC. 15 projects are associated with Pine Gate Renewables and/or Albedo Development Company.

While the Company has not received FERC authorization to lower its PURPA must buy obligation threshold prior to this IRP filing, the Company anticipates that FERC will rule on the Company's application during this proceeding. Therefore, pursuant to the Commission's directive in Case No. U-20905 *et al.*, the Company has provided rationale as to why a Standard Offer cap of 5 MW is not appropriate. In addition, and in accordance with MCL 460.6v, the Company agrees to publish on its website the Company's proposed template contract for PPAs with QFs greater than 100 kW but less than or equal to 5 MW. QFs that participate in the Company's annual solicitation process will also be provided the Company's template PPA prior to the issuance of the RFP. MCL 460.6v provides that the terms of a template PPA are not binding on either an electric utility or a QF and may be negotiated and altered upon agreement between an electric utility and a QF.

Q. Does the Company have any additional proposed changes to the Standard Offer?

A. Yes. The Company proposes to update the basis for capacity compensation for the Standard Offer Contract and Standard Offer Tariff. In Case No. U-18090, the Commission issued an Order on July 31, 2017 that requires the Company to pay for capacity using the methodology implemented by MISO at the time the contract is executed for any QFs up to 2 MW in size. See Case No. U-18090, July 31, 2017 Opinion and Order, pages 25-26. MISO is continuing to pursue changes to its resource adequacy construct that are expected to result in a seasonal, instead of annual, resource adequacy period by Planning Year 2023/2024. Company witness Thomas P. Clark discusses these changes further in his direct testimony. As part of the change, the Company anticipates that the winter capacity accreditation for solar will be substantially reduced compared to the current summer test. Compensating QFs for unusable capacity results in unnecessary costs for the Company and its customers. Therefore, this preferential treatment for QFs up to 2 MW in size should be rescinded to protect customers from an unnecessary increase in cost.

Since the July 31, 2017 Order in Case No. U-18090, the Company has developed and incorporated a new method of compensating for capacity that equally shares the benefit or harm between the Company and its PPA suppliers for any changes that MISO makes to the capacity construct. This methodology results in the Company receiving the entire capacity accredited to the generator and compensating the supplier for the average between: (i) the MISO methodology established in accordance with the MISO Business Practice Manual ("BPM") at the time the contract is executed; and (ii) the MISO methodology established in accordance with the MISO BPM at the time capacity is accredited to the generator for a resource adequacy planning period. The Company has implemented this methodology into several solar PURPA PPAs and PPAs executed as a result of the IRP competitive solicitation process. For these reasons, the Company proposes to update the Standard Offer Contract and Standard Offer Tariff 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.

Q. If the Commission does ultimately find that QFs are eligible to receive the Company's full avoided cost rates outside of the annual solicitation process, what PPA term length does the Company propose for QF PPAs.

A. As explained above, consistent with FERC Order 872, the Company does not support the awarding of the Company's full avoided cost rates outside of the annual solicitation process.[10] However, if the Commission does ultimately find the QFs are eligible to receive

[10] The Company intends to continue to offer full avoided costs based on the solicitations to QFs up to the Company's must buy obligation that had a PPA for both energy and capacity on January 1, 2019.

the Company's full avoided cost rates outside of the annual solicitation process in a manner consistent with the Company's current PURPA avoided cost construct, the Company proposes that such PPAs should be at a term up to 20 years in duration. As further described later in my testimony, the Company intends to change the term lengths of PPAs solicited in the IRP competitive solicitations. While the Company believes that shorter term PPAs are preferable for the Company and its customers, the Commission's May 31, 2017 Order in Case No. U-18090 ruled that the term length offered for the Company's full avoided cost PURPA PPAs would be up to 20 years. Therefore, without limiting the Company's ability to challenge this term length in future cases, the Company proposes to offer full avoided cost rate PURPA PPAs term lengths up to 20 years.

Q. What does the Company propose with respect to the Company's currently approved reduced avoided cost rate?

A. The IRP Settlement Agreement provides for a reduced avoided cost rate structure based on MISO PRA capacity rate and either: (i) a 10-year term based on a forecast of LMPs for the first five years and year six through year 10 of the term will be equal to the price of energy in the fifth year of the LMP forecast; or (ii) actual LMPs for 15 years. This rate structure is currently available to QFs when the Company does not have a capacity need. Given FERC's guidance in FERC Order 872 that a utility's avoided capacity cost is zero if it is competitively soliciting its full capacity needs and additional capacity is not needed, the reduced avoided cost capacity rate (i.e. the MISO PRA capacity rate) should be removed from the reduced avoided cost rate.

Q. Please address the Commission's direction with respect to the formation of Legally Enforceable Obligations ("LEO") by QFs under PURPA.

A. In its January 21, 2021 Order in Case No. U-20905 *et al.*, the Commission directed "each utility, as part of its next biennial review application, to provide clear guidance on the criteria it will use to evaluate a QF's commercial viability and financial commitment in determining whether an LEO has been formed, again consistent with FERC and Commission precedent."

Q. What is the Company's proposed criteria on the formation of LEOs by QFs?

A. As an initial matter, the Company does not believe that individual utility biennial filings, like this IRP proceeding, are the appropriate forum to consider the formation of LEOs under PURPA because it would unreasonably result in different LEO standards for each Michigan utility. If the Commission desires to adopt specific criteria for the formation of a LEO, the Commission should consider such criteria in a proceeding that involves all Michigan utilities. There should be uniformity in the LEO criteria required of all Michigan utilities so that one or more utilities is not required to utilize a potentially less stringent LEO standard. In DTE Electric Company's recent PURPA avoided cost case in Case No. U-18091, the Commission approved changes to the structure of DTE Electric Company's Standard Offer "in the interest of more uniform QF development across the State." Case No. U-18091, July 31, 2017 Opinion and Order, page 21. The Commission should reach a similar finding with respect to the criteria for LEO formation and find that the criteria for the formation of a LEO should be uniform throughout Michigan.

In addition to the above, and as explained in more detail in the Company's November 30, 2020 Comments submitted in Case No. U-20905 *et al.*, in FERC Order 872, FERC provided minimum guidance for the establishment of a LEO. FERC established new regulations, effective at the end of 2020, "to require QFs to demonstrate that a proposed project is commercially viable and that the QF has a financial commitment to construct the proposed project, pursuant to objective, reasonable, state-determined criteria in order to be eligible for a LEO." FERC Order 872, pages 373-374. FERC also affirmed that "states have flexibility as to what constitutes an acceptable showing of commercial viability and financial commitment, albeit subject to the criteria being objective and reasonable." *Id*.

The Commission should affirm FERC's directive in FERC Order 872 regarding minimum requirements for the establishment of a LEO and also make clear that a QF's meeting of these requirements does not, in and of itself, mean that the QF has formed a LEO. In particular, consistent with comments submitted by Consumers Energy to the Commission in the past, the MPSC should emphasize that a QF must demonstrate that it is commercially viable and has made appropriate financial commitments to demonstrate its viability, before a LEO can be established. In addition to affirming FERC's minimum LEO requirements, the Commission should clarify that, in the process of establishing whether or not a QF project has a LEO, the Commission will continue to assess each QF project on a case-by-case basis to determine if the QF project is a real, viable project on which customers can rely.

If the Commission desires to establish specific LEO criteria, in the alternative to the current case-by-case approach described above, the Company proposes to use a modified version of the criteria submitted by the Company on May 1, 2020 in the context of Staff's LEO Workgroup. Specifically:

(1) A legally enforceable obligation is established between the qualifying facility and the electric utility when a qualifying facility has:

(a) Provided an electric utility with documentation demonstrating that, under 18 C.F.R. § 292:

(i) The facility is a "qualifying facility;" and

(ii) The facility has been certified as a qualifying facility with or by the Federal Energy Regulatory Commission.

(b) Provided the electric utility all of the following:

(i) A description of the location of the project and its proximity to other projects within one (1) mile of the project, which are owned or controlled by the same developer or owner or otherwise affiliated with the qualifying facility,

(ii) An estimated, non-binding, good faith estimate of the energy production for the project that includes the kilowatt-hours to be produced by the qualifying facility for each month and year of the entire term of the project's anticipated power purchase agreement,

(iii) An Internal Revenue Service Form W-9,

(iv) Evidence of an engineering, procurement, and construction program that will result in commercial operation of the project (and the project's interconnection) on a defined schedule that is consistent with the capacity needs of the purchasing utility,

(v) Evidence of a secured commitment from major equipment manufacturers for the delivery and/or installation of all major equipment to be utilized by the project,

(vi) Evidence that the project is financeable, and

(vii) Proof of fuel security, or, if the project is for wind, solar, or hydroelectric generation, the amount of available fuel at the project's location.

(c) Demonstrated that it has taken meaningful steps to obtain site control adequate to commence construction of the project at the proposed location.

(d) If qualifying as a "cogeneration facility" under R 460.1052(1)(a) provided the electric utility with written proof of a steam host that is willing to contract for steam over the full term of the project's anticipated power purchase agreement for a cogeneration facility.

(e) Submitted an interconnection application and completed the process of obtaining any necessary interconnection study results (engineering review and/or distribution system study results) from the Company under R 460.620.

(f) Agreed, in writing, to pay the system construction or modification costs identified in any interconnection study pursuant to R 460.620(10).

(g) Unilaterally signed and tendered a proposed power purchase

> agreement ("PPA") to the purchasing utility with a price term equal to either:
>
> > (i) the existing standard offer rate in accordance with the applicable standard tariff provisions as approved by the commission for qualifying facilities eligible for standard offer rates; or
> >
> > (ii) a price term consistent with the purchasing utility's avoided costs, with specified beginning and ending dates for delivery of energy, capacity, or both to be purchased by the utility

The Company's above recommended criteria are generally consistent with Staff's second Strawman Proposal for Interconnection, DG, and LEO standards ("Strawman Proposal") published by Staff on February 28, 2020. However, the Company's proposed additions to Staff's Strawman Proposal are intended to ensure that, at a minimum, the proposed LEO criteria be revised to require: (i) that meaningful steps have been taken to secure site control, consistent with FERC Order 872; (ii) that developers be required to provide evidence of engineering, procurement, and construction agreements associated with each project; and (iii) that developers be required to provide evidence that their project is financeable. These recommendations are based on the Company's actual experience to date, which includes encountering developers with competing "options" to lease the same parcel of land, and significant uncertainty regarding project financing, equipment availability, project construction schedules, and project development progress.

The Company is also proposing, consistent with the Commission's existing interconnection rules, that QFs be required to obtain any necessary interconnection studies from the Company and then agree, in writing, to pay any system construction or modification costs identified in those studies. These requirements do not place formation of a LEO solely in the hands of the Company because the process and timing for such studies is objective, predictable, and governed by Commission rules. In the Company's recent experience, many proposed QF projects have turned out to be non-viable upon receipt of interconnection costs. The only way to ensure that a QF is in fact commercially viable, consistent with FERC Order 872, is to ensure that the QF has obtained interconnection cost estimates under the MPSC-prescribed process and agreed to pay those costs.

In addition, the Company submits that formation of a LEO requires "a binding commitment by both sides to the agreement or obligation – the obligation by the utility to purchase the power and the obligation by the QF to provide energy and capacity upon which the utility and its customers can rely." See September 26, 2019 Order in MPSC Case No. U-20156, Page 53. Without the additional requirements recommended by Consumers Energy, the Company is concerned that a LEO could be formed without a true commitment by developers. Allowing a LEO to arise without additional evidence of that commitment will not "strike the right balance between access for QFs on the one hand and system reliability and certainty in utility planning and procurement to protect ratepayers on the other hand." See September 26, 2019 Order in MPSC Case No. U-20156, Page 54.

Furthermore, the Company requests clarification from the Commission as to when a LEO is abrogated. Even after a LEO is formed by a QF, there may be modifications made which materially change the nature, and potential viability, of a proposed project. Since the formation of a LEO hinges on the viability of a project, a formed LEO cannot continue in perpetuity for an undeveloped project. Therefore, clear guidance is needed from the Commission to define when a previously formed LEO has been terminated. For example, a QF that proposes a material modification to its project design, and therefore will require new interconnection studies and new interconnection cost estimates, should be required to re-affirm its commitment to paying those costs, that it has taken meaningful steps toward site control for the modified project, and provide evidence that the revised project remains financeable. In the Company's experience, many QF projects languish for years in the Consumers Energy interconnection queue and uncertainty around the potential future plans for such projects can cause significant uncertainty for the Company's resource planning.

SECTION V: COMPETITIVE SOLICITATIONS

Summary of 2019 and 2020 Competitive Solicitations

Q. Are you familiar with the Company's competitive solicitation process for IRP supply-side resources?

A. Yes. In Case No. U-20165, I sponsored direct and rebuttal testimony describing the Company's plans to utilize competitive solicitations to procure PPAs and Company-owned solar resources to meet the IRP Settlement Agreement PCA. I also have management oversight of the administration of competitive solicitations for new generation resources.

Q. Please provide a summary of the competitive solicitation process from the IRP Settlement Agreement.

A. In accordance with the IRP Settlement Agreement, the Company uses an annual solicitation process to procure the supply-side technologies specified in the IRP PCA. Each solicitation must meet the following requirements:

1. Administration of the solicitation by an independent evaluator ("IE") (also referred to as "Independent Administrator" in Company's regulatory filings);
2. The Company makes the selection of provisional award from a blind ranking of evaluated proposals as provided by the IE;
3. QFs are permitted to bid any technology into the solicitation;

4. The cost and value of the proposed project are to be considered to determine the net cost as may be modified by value added criteria;

5. The solicitation will follow the 2008 Guidelines for Competitive Request for Proposal of Renewable and Advanced Cleaner Energy from the Commissions December 4, 2008 Order in Case No. U-15800 plus (i) the issuance of public notice to interested parties, and (ii) providing the terms of the contract with the RFP;

6. Respondents may select a PPA term length up to the depreciation schedule of a similar Company asset (i.e. 25 years for solar);

7. 50% will be sourced from PPAs and 50% will be owned by the Company, however the Company can select more than 50% from PPA capacity at its sole discretion; and

8. The Company must inform respondents of the impact of the FCM on PPA proposals.

Additionally, the Company's solicitations will be required to follow any future applicable guidelines for competitive procurement that the Commission may adopt.

Q. Has the Company gained additional experience and insight on the effectiveness of these solicitation requirements since the approval of the IRP Settlement?

A. Yes. The Company's, third-party independent administrator, Enel X, issued the first annual solicitation on September 30, 2019 to procure 300 MW of new solar capacity to be installed by 2022. A total of 49 unique proposals covering 34 unique projects and representing nearly 2,000 MW of capacity, were submitted on a confidential basis in the 2019 competitive solicitation. Of those, 24 proposals were offered as a BTA and 25 were offered as long-term PPAs. Fifteen projects that participated were PURPA QFs up to the Company's current must buy obligation of 20 MW.

The Company entered into a 140 MW PPA with Calhoun Solar Energy, LLC and a 150 MW Build-Transfer Agreement ("BTA") with Mustang Mile, LLC for the development and construction of the Mustang Mile project that will be owned and operated by the Company. These agreements were filed in Case No. U-20165 and the PPA and BTA were both approved by the Commission on April 8, 2021. In accordance with the IRP Settlement Agreement, the Company filed updated PURPA full avoided costs including the Standard Offer Contract and Standard Offer Tariff in Case No. U-20165 on April 14, 2021, which were approved by the Commission's May 26, 2021 Order in that docket. The Company is currently in discussions with QFs to fill the remaining 10 MW of capacity. Enel X has produced a final report on the 2019 IRP solar competitive solicitation which contains more details on the Company's first IRP-based competitive solicitation process. This report is provided as Exhibit A-48 (KGT-4).

On July 29, 2020, Enel X issued the second annual solicitation to procure 300 MW of new solar capacity to be installed by 2023. A total of 43 unique projects representing nearly 2,500 MW of capacity, were submitted on a confidential basis in the 2020 competitive solicitation. Of those, 21 unique projects were offered as a BTA and 19 unique projects were offered as long term PPAs. Five unique projects that participated were PURPA QFs up to the Company's must buy obligation threshold of 20 MW. At the time of the preparation of this filing, the Company has executed one PPA which is expected to be filed for MPSC approval in July 2021 and is in negotiations with developers on several projects to fill the solicited capacity. The Company's IE will be issuing and completing the 500 MW 2021 solicitation for 2024 resources while this case is ongoing.

Q. What role does the IE have in the solicitations?

A Enel X, as the IE of the Company's 2019 and 2020 solicitations, supported the Company by assisting in the RFP development, advertising and releasing the RFP, independently and without bias administered fair and transparent solicitations, provided individualistic support to respondents, collected and evaluated proposals, produced blind shortlists, and provided regulatory support post solicitation. Enel X has also been supporting the Company's continuous improvement efforts to improve the Company's competitive procurement practices.

Q. What were the criteria used to rank proposals?

A Proposals were first screened based on factors identified by the Company as necessary to ensure a viable project. These include factors such as minimum and maximum capacity offer, contract length, interconnection status, feasibility location site control and creditworthiness. Per Section 9.2 of the Consumers Energy RFP; Proposals were to be evaluated based on projected costs, projected commodity value, and value-added criteria. The economic evaluation consisted of first calculating the total projected cost of a proposal. Second, the projected value of the commodities provided by the proposed project was subtracted from the total projected cost to calculate a net cost for the proposal. Lastly, the value-added criteria was subtracted from the net cost to determine the final, adjusted net cost of the proposal. Projects were then ranked based on their adjusted net cost. A blind ranking of the proposals was then provided by Enel X to the Company for review and provisional award of projects to move forward with due diligence and negotiation between the Company and the proposal developer.

Q. What impact did the FCM have on the solicitations?

A PPAs are subject to the FCM approved as part of the IRP Settlement Agreement in Case No. U-20165. The FCM was included in the economic evaluation of all PPA proposals, and its inclusion in the evaluation did not affect the ranking or impact the outcome of the solicitation results in any way.

Q. How are the new solar assets represented in this filing?

A. The details about the size, performance, and costs of the 2019 and 2020 solicitation resources was unknown at the time that input assumptions were finalized for inclusion in the base assumptions for IRP modeling. Therefore, the Company relied on proxy assumptions for this filing including 300 MW in 2023, 300 MW in 2024, and 500 MW in 2025 for base modeling assumptions. Of this capacity, the Company assumed that 50% would be owned by the Company and 50% would come from PPAs. The base modeling assumption for PPAs included in this IRP are detailed in Exhibit A-45 (KGT-1).

<u>Proposed Changes to Future Competitive Solicitations</u>

Q. Is the Company proposing any changes to the annual competitive solicitation process in the IRP Settlement Agreement?

A. Yes. Based on the Company's experience with the 2019 and 2020 solicitations, there are several improvements that the Company proposes related to the targeted MWs acquired in each solicitation and timing of project Commercial Operation Dates ("COD"); the solicitation ownership structure; the manner in which MWs acquired in each solicitation will be ultimately reconciled, the term length of PPAs, and the evaluation of bids.

Q. Please explain the Company's proposed changes related to the targeted MWs acquired in each solicitation and timing of project COD.

A. The Company is challenged to balance the "lumpiness" of achieving a target capacity to the exact MW with resources as large as 150-200 MW in size. Finding the perfect blend of projects to get an exact amount of capacity (e.g. 300 MW) is not a simple or easily repeatable process. Further, the Company must try to achieve exactly 50% PPA and 50% Company-owned in each solicitation further complicating the lumpiness issue. For example, if the Company has a target of 150 MW and the best evaluated project is 50 MW with the second best evaluated project at 150 MW, the Company may prefer to pursue both projects, or perhaps just the 50 MW, and make up the difference in a future solicitation. However, the current requirement to award any shortfall to PURPA incentivizes the Company to over-procure the Company-owned tranche of the solicitation to prevent missing an opportunity to own and operate half of its supply portfolio. Further, with the 50% PPA and 50% Company-owned ownership structure required in each solicitation under the IRP Settlement Agreement, the Company must similarly over-award on the PPA tranche to match any over-award on the Company-owned tranche. This iterative process creates uncertainty, inefficiency, and additional cost within post-solicitation activities which has resulted in delays and frustration in the negotiation process.

To obtain the best projects for customers, the Company requires additional flexibility to be able to select more or less capacity than the solicited MW target in each annual solicitation. There may be solicitations that result in extremely high-cost proposals that the Company would not want to obligate customers to pay. Similarly, there may be solicitations that result in extremely low-cost proposals that the Company would like to acquire to get the best costs for customers. Therefore, the Company proposes to both (i) remove the requirement that leftover capacity from each solicitation is made available to PURPA QFs, as discussed in the prior section of my direct testimony, and (ii) add flexibility to pursue more or less capacity in any given annual solicitation to more efficiently track towards the long term PCA acquisition targets. With the approval of these proposals, the Company will continue to file the PPAs and Company-owned assets for

Commission approval, which will ensure that the flexibility requested by the Company will be subject to Commission oversight.

Since the flexibility provided to the Company in each solicitation allows the Company to procure more than the targeted MW amount in any given year, the Company will reconcile the total MWs procured in the prior solicitations with the MWs needed to implement the PCA in each subsequent IRP proceeding. In other words, the Company would not reconcile the annually acquired MWs against the targeted PCA MWs between the annual solicitations. The IRP-based reconciliation would also address instances where the Company is required to acquire supply-side capacity outside of the solicitation, like the PURPA Settlement Agreement. Since the Company may ultimately procure more or less than the targeted MW amount, the Company may make upward or downward adjustments to the to-be-acquired MWs in the PCA in future IRP proceedings.

In addition to the above, and as discussed in more detail below, the Company proposes to generally maintain the current ownership structure of the solicitation process, with the caveat that the Company may own at least 50% of the new capacity with the remaining capacity coming from either PPAs or Company-owned resources, based on economics. Because the Company is proposing to acquire potentially more than 50% of new capacity from Company-owned resources, the IRP-based reconciliation would also address instances where the Company decided to acquire Company-owned projects instead of PPAs. The Company would provide the basis for its decisions to pursue Company-owned projects over PPAs in future proceedings seeking approval of the specific Company-owned project.

Furthermore, the Company proposes that the at least 50% Company-owned and 50% either PPA or Company-owned ownership structure be viewed over a longer term, beginning with the IRP Settlement Agreement, and revisited in each IRP, versus annually, due to the lumpiness of utility scale solar as previously discussed. This will allow sufficient flexibility to acquire potentially more or less than the targeted MW amount in each solicitation and account for instances where the Company may be required to take on other supply-side resources. As demonstrated in the table below, the Company is significantly oversupplied with solar PPAs, beyond the originally intended 50% PPA and 50% Company-owned ownership structure established in the IRP Settlement Agreement, due in part to the PURPA Settlement Agreement. Since the IRP Settlement Agreement, the Company has added the following capacity to its supply-side portfolio resulting in only 20% Company ownership and 80% PPA:

Resource	Ownership	Capacity (MW)	Source
PURPA Solar	PPA	434	PURPA Settlement Agreement
Calhoun Solar	PPA	140	2019 RFP
Mustang Mile	BTA	150	2019 RFP
PURPA Solar	PPA	10	2019 RFP
Total		**734**	

Due to events like the PURPA Settlement Agreement, it is more reasonable to meet the Company's proposed ownership structure over the longer-term period described above. Therefore, the Company proposes that the requirement to establish ownership in each solicitation be replaced with a target of maintaining the structure, beginning with the IRP Settlement Agreement, in each subsequent IRP.

The Company also intends to provide additional flexibility on the timing between the annual solicitations and the required COD prescribed in each solicitation. Through the first two solicitations, one common issue is the proposal's interconnection schedule and required network upgrades misaligning with the COD deadlines of the solicitation. The rigidity of the current three-year cycle is causing uncertainty in the Company's ability to procure the right amount of capacity when needed to meet MISO's Planning Reserve Margin Requirement ("PRMR") since project schedules tend to slip for reason's outside of the Company's or a developer's control. Similarly, the Company has experienced proposals that are "too developed" meaning that the project would result in significant investment before the Commission could review and issue an order on the reasonableness of procuring the asset.

Q. Please explain the Company's proposed changes related to the ownership structure of the resources selected in the solicitations.

A. In future solicitations, the Company proposes to acquire *at least* 50% of the capacity from Company-owned resources and 50% from either PPAs or Company-owned resources, based on economics. The Company is proposing this modification to the current solicitation structure, which caps the Company's acquisition of Company-owned resources at 50%, because it has the unintended consequence of restricting the Company's ability to meet its annual solicitation capacity. Projects that are ultimately owned and operated by the Company are not easily scalable and typically are the most economic when constructed as initially designed. However, PPAs are scalable because the supplier can more easily line up several buyers to procure a portion of the output or sell a portion into the MISO market. For example, the Company's 100 MW PPA with River Fork Solar results in the purchase of about 67% of the 149 MW plant's output. Similarly, the Company's 140 MW PPA with Calhoun Solar Energy results in the purchase of about 70% of the 200 MW plant's output. The Company would expect to see better alignment with the total solicited capacity if the Company were able to own at least 50% and allow the PPAs to be scalable to fill the remaining capacity. Therefore, the Company proposes to own at least 50% of the new solar capacity procured through the IRP.

Q. How does the Company view the costs and benefits of Company-owned projects compared to long term PPAs?

A. There are several significant differences between Company-owned projects and long term PPAs for customers including: (i) value; (ii) cost; (iii) risk; and (iv) regulatory oversight. First, for Company-owned projects, customers have an inherent economic optionality built into the facility. Throughout the useful life of the asset, the Company can, through economic analysis under the MPSC's oversight, make additional investments into the facility to extend the plant's useful life, improve the efficiency of plant, or economically retire the plant. This optionality may only be realized in PPAs if contractually included in the PPA as an option to extend, purchase, or terminate. Rather, PPAs are an obligation on behalf of both parties where the supplier can make similar decisions to extend the useful life or improve the efficiency of the plant but is able to retain the value of the economic decision without conveying it to the Company or our customers. Typically, the Company's PPAs include early termination security provisions that require a financial obligation for either party to terminate the PPA. In the case that a supplier terminates the PPA, the Company would receive a financial payment, but would still need to contract with, purchase from the wholesale market, or build replacement capacity and energy to fill the void in supply created by such termination.

Second, the costs of Company-owned facilities are typically front loaded in capital investment with some amount of ongoing Operating and Maintenance ("O&M") expense, both of which are subject to recovery through regulatory approval in each electric rate case. The reasonableness of expense(s), whether capital or O&M, are constantly reviewed through the life of the asset. However, PPAs are typically subject to review and approval of the PPA at a single point in time before the PPA begins. Then, once approved and effective, the PPA rates are locked in for the life of the asset. The ability for the Company to challenge decisions made by a supplier are limited to the performance and availability guarantees built into the contract from the start. For this reason, the Company, and ultimately its customers, experience misalignment between PPAs and the wholesale market as market conditions tend to change over the term of a PPA. When PPA rates exceed market costs, the Company's customers take on the additional cost, and when PPA rates are lower than market costs, the Company's customers realize the cost savings, both of which occur through the PSCR mechanism. Historically, the Company's PPA rates have exceeded actual wholesale market costs even though the costs could be based on wholesale market forecasts.

Third, there is a significant difference in both the oversight by the MPSC, as well as commitments to the communities in which facilities are located. PPA oversight, once approved, is generally limited to ensuring that the terms of a PPA are met. The MPSC does not typically have the authority to question PPA supplier decision-making. Whereas, the Company engages with the MPSC in numerous filings annually, where the MPSC has the authority to challenge the Company's decisions and ultimately determine whether or not the costs incurred will be recoverable from customers. The Company owns and operates generation and has retail customers throughout the lower peninsula of Michigan. The Company has an obligation to care for the communities in which it serves gas and electric customers. PPA suppliers, especially when set up as LLCs, do not have the same responsibilities to care for customer's communities.

Q. Please explain the Company's proposed changes related to the PPA term sought in each solicitation.

A. Currently, in accordance with the competitive solicitation process approved in the IRP Settlement Agreement, the Company solicits PPA terms lengths up to 25 years in its annual solicitations. While the Company recognizes that the PPA term lengths that it solicits is ultimately a management decision, going forward, the Company intends to solicit PPAs which are a maximum of 15 years in length. The Company will also solicit PPAs which provide for an option to purchase or extend the PPA term beginning in the 10th year of the PPA and continuing in five-year increments thereafter.

Q. Why is the Company interested in pursuing options to purchase PPA facilities or extend the term of the PPA?

A. There are significant differences in the value provided for customers from Company-owned facilities versus PPAs. As previously discussed, Company-owned facilities include inherent optionality for customers to maximize the value of the facility by economically improving, extending, or retiring a generating asset. Historically, the Company has partially addressed this value by including a terminal value in the economic analysis of Company-owned facilities. However, terminal value as implemented by the Company only reflects the option to extend, not the options available to customers for the Company to improve or extend the life of an asset. In an effort to obtain a more apples-to-apples comparison in value provided by Company-owned assets and PPAs, the Company can build the optionality into the PPAs through an option to purchase or extend the PPA at a specific time during the PPA term. Based on recent research into renewable PPA terms and competitive procurement, the Company anticipates that shortening the PPA term and including options that the Company may enforce during the PPA term will result in financeable PPAs for the developer while increasing value to our customers.

Q. Has the Company commissioned any independent analysis to support its position on PPA term length?

A. Yes. The Company was aware that non-utility corporations had been able to procure a variety of renewable PPAs to meet renewable or sustainability initiatives. The Company hired Wood Mackenzie ("WoodMac") to conduct research into the competitive procurement and renewable PPA strategies conducted throughout the utility and non-utility sector to determine if there are additional best practices that the Company could adopt to improve the acquisition of renewable technologies for our customers.

Q. Please explain Exhibit A-46 (KGT-2).

A. Exhibit A-46 (KGT-2) is a final, independent report that WoodMac created to summarize its findings of the research requested by the Company on renewable PPA strategy and competitive procurement. The first topic summarized in the report on pages 4 through 14 of the Exhibit is a comparison of traditional utility PPA structures to those utilized by the Commercial and Industrial ("C&I") customer segment. The second topic summarized in the report on pages 15 through 20 is a comparison of the Company's PPA procurement strategy to the processes utilized by C&I customers. In both sections, WoodMac has included a review of risks, opportunities, and/or evaluation of the Company's current practices compared to C&I customers.

Q. Based on the research conducted by WoodMac, what additional changes does the Company propose to make to its competitive procurement process?

A. With respect to PPAs, the Company intends to procure PPAs with a maximum term of 15 years as previously discussed. The C&I customer segment is successfully balancing buyer flexibility with developer certainty with contract terms in the 12 to 15-year timeframe. This shorter initial period will help ensure that the Company's customers are not saddled with higher PPA prices in the later years of a PPA. Additionally, the Company intends to include the option to extend or option to purchase in future PPAs that it acquires through the competitive solicitation process to increase the value of the PPA for customers. The combination of shorter term PPA with these options is expected to result in better PPAs for our customers.

The WoodMac report identifies several additional opportunities or risks for the Company to consider including: (i) the potential for negative market prices; (ii) diversification of production risk; (iii) the evaluation of bundled and unbundled environmental attributes; (iv) wholesale price separation between the project and the Company's load; and (v) inclusion of the Right of First Refusal to purchase at the end of a PPA. Some of these topics can be incorporated into the solicitations under the current IRP Settlement Agreement as they are not material to the solicitation process, but rather, the specific terms of the PPA offered through the solicitation. The Company will consider WoodMac's suggestions in the upcoming solicitations.

With respect to the competitive procurement process, there are changes that the Company is seeking in this IRP including: (i) flexibility on COD dates; and (ii) laddering procurement. First, the Company has experienced delays in both transmission and distribution connected projects, leading to a lower probability of meeting the Company's PRMR in years when the Company's surplus capacity is small. The Company and its customers are expected to have a greater certainty of procuring an adequate amount of resources through the "laddered approach" suggested by WoodMac. The Company would intend to procure in a single solicitation, capacity from resources with a variety of start dates from approximately 3-5 years from the solicitation. This flexibility in procurement will provide more certainty for resource planning by acquiring resources further in advance of COD, and for PPAs, with a variety of contract term lengths to limit the amount of capacity leaving the Company's supply in a single year at the end of the PPA(s) term.

Regarding the competitive procurement section in the WoodMac report, there are also several additional opportunities or risks for the Company to consider including: (i) technology limitation; (ii) geographic limitation; and (iii) flexibility to understand pricing. Some of these topics including technology and location are applicable for other types of Company solicitations, including VGP solicitations or bilateral capacity auctions where the technology or MISO Local Resource Zone ("LRZ") are not prescribed like it is in the IRP. There are some topics that can be incorporated into the solicitations under the current IRP Settlement Agreement through the use of multiple tranches or eligible bidding options that the Company can further purse in the upcoming solicitations.

Q. Please explain the Company's proposed changes to the evaluation of bids in the solicitation process.

A. The Company intends to increase the flexibility for how to conduct and update its evaluation process from the rigidity specified in the IRP Settlement Agreement. The Company agrees with the general construct that the cost of a resource and the value provided (including non-commodity value) are important to economic considerations of resource. Additionally, there are mitigation attributes of a proposal that are important to consider in each solicitation. The objective of a competitive solicitation to drive down costs while maximizing value is best accomplished through continuous improvement based on lessons learned and experience. Therefore, the Company intends to remove two prescribed elements from the evaluation process, including (i) ranking proposals on a net cost basis, and (ii) establishing Value-Added Criteria on a $/MWh as used in the 2019-2021 solicitations. First, the net cost concept does not appropriately scale with the changes in cost and value if the two factors move substantially. There are other metrics that should be considered such as cost to value ratios. For example, if Proposal A has a cost of $95/MWh and a value of $100/MWh, the net cost (value) is ($5)/MWh; and if Proposal B has a cost of $45 and a value of $50/MWh, the net cost (value) is ($5)/MWh. However, if the value is based on a volatile commodity, the lower risk project is likely Proposal B since Proposal A relies on a higher estimated value. Using this example, Proposal A would have a cost to value ratio of 95% and Proposal B would have a cost to value ratio of 90% which means that Proposal B is the preferred project using the cost-to-value ratio methodology. An alternative perspective using cost to value ratios is that the reciprocal of the ratio illustrates how much value is received for each dollar spent. For Proposal A for each dollar spent, customers would receive $1.05 in value and for Proposal B for each dollar spent customers would receive $1.11 in value.

Second, in the 2019 through 2021 solicitations the Company established all non-pricing factors as Value Added Criteria on a $/MWh basis which was more divisive than traditional points-based evaluations for unique properties of a proposal. Similarly, to address some of the qualitative aspects of a project including development progress and project risk, the Company increased the screening criteria for eligible proposals. As the Company is seeking more flexibility on the timing of CODs in each proposal, it is unlikely that a robust screening criterion will be flexible enough to handle the variety of developmental status that will be bid into the solicitation. The Company supports transparency in the solicitation process for respondents to understand how proposals will be evaluated, but this transparency must be balanced with the Company's ability to improve the evaluation process through the flexibility to adopt best practices from the utility and C&I procurement processes.

Q. Are there any other changes or clarifications related to the Company's competitive solicitation process?

A. Yes. While the Company intends to meet its full supply-side capacity needs with the annual competitive solicitation process, the Company also requires opportunities for learning and development. To that end, the Company intends to pursue supply-side resource pilots outside of the competitive solicitation process. These pilots will allow the Company to better understand how emerging technologies fit within the Company's resource portfolio and how those emerging technologies may be better considered in a future IRP. The purpose of these pilots is not to secure capacity, displace PCA capacity acquisitions, or otherwise to meet the Company's capacity needs. Rather, any projects pursued through the pilot process would be intended to expand the Company's knowledge and experience for unique, novel projects. If the Company ultimately pursues a specific supply-side resource pilot, and seeks cost recovery, the Company will present that pilot in a future rate case, similar to the battery pilots presented in the Company's 2020 electric rate case, Case No. U-20697.

Q. Are there other situations in which the Company may need to acquire capacity?

A. Yes. It is possible that the Company could be faced with a short-term capacity need due to an unforeseen change in its generation portfolio or resource acquisition plan. One such circumstance, as previously discussed in my testimony, could be due to the slippage in the schedules of both PURPA and IRP solar resources that are relied on as part of the Company's long-term capacity planning. Another circumstance could be the catastrophic outage of an existing capacity resource. Under these circumstances, the Company could be in a position in future Planning Years where its capacity supply will not meet its MISO PRMR on a short-term basis. In that situation, the Company cannot use the annual solicitation process to fill that need due to the time required to potentially build a new resource. If the Company determines that a significant shortfall of capacity is needed for an upcoming Planning Year, the Company would issue a separate capacity solicitation, such as the Company's prior reverse auctions for capacity, to reduce cost risk for customers as it has done in the past. The Company needs flexibility to make such short-term capacity purchases in order to address emergent, unplanned capacity shortages and to protect customers from the potentially significant costs associated with falling short of MISO PRMR requirements.

Q. If the proposed changes to the solicitation process are adopted, will there be opportunities available to QFs?

A. Yes. As described above, the Company intends to allow QFs of any technology to continue to bid into its competitive solicitations. As previously described, the Company has expanded its DG program for QFs up to 150 kW in size that meet certain program requirements. Further, QFs can pursue a PPA under the reduced avoided cost rates, as previously described. Lastly, the Company anticipates that wholesale market participation for QFs 100 kW and up will become readily available through the MISO market as a result of FERC Order 2222.

Q. How does the Company intend to seek approval of the projects selected in the competitive solicitation process?

A. Subsequent to the completion of the Company's 2019 competitive solicitation, the Company filed the selected PPA, BTA, and the avoided cost rates stemming from the 2019 competitive solicitation for *ex parte* approval in the 2018 IRP docket, Case No. U-20165. In the Commission's Orders issued on April 8, 2021 and May 26, 2021 in Case No. U-20165, the Commission approved the Company's filings. Based on the process established in Case No. U-20165, the Company proposes to continue filing the PPAs, Company-owned projects, and avoided cost rates for *ex parte* approval in the docket of the most recently approved IRP.

The above expedited approval process is beneficial to both the Company and the counterparties to PPAs and Company-owned projects because it provides assurance that the Commission deems the selection of those projects to be reasonable. With respect to Company-owned projects like BTAs, it is typical that milestone payments begin shortly after execution. This means that the parties are required to begin performing under a contract prior to the time that rate approval can be provided in a rate case, Certificate of Necessity proceeding, or subsequent IRP proceeding. The expedited approval process is also beneficial from a PURPA perspective because it will result in the timely approval of full avoided cost rates stemming from each solicitation. If lengthy proceedings are required for the approval of the resources selected in each competitive solicitation, it is possible that the proceedings for different competitive solicitations will overlap making it unclear which full avoided cost rates applies to certain periods of time.

In support of the request for *ex parte* approval of the resources selected in the competitive solicitation process, the Company will show that the selected resources are consistent with or below the modeled cost of that resource in the Company's most recently approved IRP. Furthermore, the Company will request rate recovery of the projects which will be owned by the Company in the next electric rate case filed after execution of the agreement for the Company owned resource.

SECTION VI: 2021 NATURAL GAS PLANT RFP

Q. Did the Company conduct a competitive solicitation for supply-side resources in addition to the solar solicitations discussed above?

A. Yes. The IRP Settlement Agreement required the Company to conduct a retirement analysis of J.H. Campbell ("Campbell") Units 1 and 2 in this IRP filing. This requirement caused the Company to evaluate the potential accelerated retirement of Campbell Units 1, 2, and 3 and the Company also considered the accelerated retirement of D.E. Karn ("Karn") Units 3 and 4 as detailed by Company witness Richard T. Blumenstock. Therefore, the

Company decided to conduct a competitive solicitation in early 2021 for existing natural gas fueled generation.

A significant amount of existing generation capacity would be necessary to accomplish an early retirement of Campbell Units 1, 2, and 3 and Karn Units 3 and 4. The Company determined that 22 gas plants from 10 different owners would meet proposed eligibility criteria and therefore qualify to participate representing 6,269 MW of eligible installed capacity. Company witness Blumenstock further explains the clear advantages in acquiring existing gas resources to support the proposed accelerated retirements of Karn Units 3 and 4 and Campbell Units 1, 2, and 3.

Q. Please provide an overview of the 2021 Natural Gas Plant RFP.

A. In order to ensure effective oversight and administration of the RFP, consistent with the solicitation guidelines set out by the FERC, described in more detail below, the Company retained an RFP Manager, CRA, as an independent third-party to design the solicitation, administer bidding, and evaluate bids prior to selection. On January 6, 2021, CRA issued an RFP to satisfy potential capacity and energy needs by acquiring up to 2,000 MW of unforced capacity ("UCAP")[11] between April 2023 and April 2026. In order to be considered in this RFP, generators were required to be existing natural gas-fueled combined cycle or combustion turbines located or transferrable to the MISO Local Resource Zone 7 ("LRZ-7), with facilities sized between 50 and 1,400 MW (UCAP). CRA developed and scheduled the publication of a Consumers Energy RFP advertisement, which was run on January 8, 2021 within a daily issue of the S&P Global Platts Megawatt Daily publication. CRA proactively reached out to the 10 different owners with expected eligible generators

[11] UCAP represents the percentage of a generating unit's installed capacity ("ICAP") deemed available after the unit's forced outage rate is taken into account.

and the parties that have participated in other solicitations administered by CRA. CRA conducted a pre-bid informational session on January 14, 2021 with prospective bidders.

Q. Please explain CRA's role in the 2021 competitive solicitation.

A. CRA, as the RFP Manager for the Company's 2021 competitive solicitation, supported the Company through RFP development, administered a fair and transparent solicitation independently and without bias, provided support to respondents, collected and evaluated proposals, and produced a recommendation on assets to advance for further due diligence.

Q. Please provide a participation summary for the 2021 competitive solicitation.

A. Five potential bidders submitted pre-qualification applications. All bidders offering facilities that met the stated qualification requirements for the RFP were prequalified. Three of the five applicants were not approved for participation. Non-qualifiers included one participant offering a facility or facilities that did not meet the requirement that projects be in service and operational as of the issuance date of the RFP. Others offered resources that did not meet the location requirement, as the facilities did not currently qualify as MISO LRZ-7 and were not capable of reclassifying as a LRZ-7 resource. The two prequalified entities submitted eligible bids encompassing a total of four generation facilities. Bids included two combined cycle facilities and two combustion turbine facilities. In total, the facilities bid into the RFP had approximately 2,000 MW of UCAP.

Q. Please explain the activities performed by CRA on the proposals submitted in the 2021 Natural Gas Plant RFP.

A. After the proposals were received, CRA as the RFP Manager:

1. Reviewed all proposals and screened the responses to ensure they conformed with all response requirements;
2. Conducted follow-up conference calls with representatives of each company submitting a conforming proposal to clarify asset-specific issues with the

information provided;

3. Evaluated all conforming proposals according to the pre-specified criteria as outlined in the RFP documents;

4. Managed bidder communication and outreach; and

5. Confirmed the winning proposals and the short list of assets to include for recommendation for advancement by the Company to the definitive agreement phase of the RFP.

Q. Please explain how proposals were evaluated in the 2021 Natural Gas Plant RFP.

A. CRA reviewed all proposals that met pre-determined qualifying criteria set forth in the RFP documentation and evaluated each based on certain pre-specified evaluation criteria. Generating assets offered into the RFP were evaluated based on:

1. Estimated Net Present Value ("NPV") for the project over a 25-year period;

2. Asset age and reliability; and

3. Asset-specific benefits and risk factors.

Q. Please explain the selections of proposals in the 2021 Natural Gas Plant RFP.

A. On March 12, 2021 the Company received a recommendation from CRA on assets to advance for further due diligence by the Company. The Company followed CRA's recommendation, which resulted in the selection of the 1058 MW UCAP Covert Generating Facility ("Covert Plant") (proposal 1), and the combination of the Dearborn Industrial Generation ("DIG Plant"), Kalamazoo River Generating Station ("Kalamazoo Plant"), and the Livingston Generating Station ("Livingston Plant"), totaling 927 MW UCAP (proposal 2). Proposal 2 was submitted by Company affiliate, CMS Enterprises Company ("CMS Enterprises"). Upon selection of the recommendation from CRA, the proposals were transferred to the Company's Generation Transformation organization for due diligence and negotiation of Purchase and Sale Agreements ("PSA") with the counterparties. Further discussion about the selected resources is included in Company witness Jeffrey E. Battaglia's direct testimony.

Q. Please explain the role of your organization and that of Company witness Battaglia in the 2021 Natural Gas Plant RFP.

A. My team is responsible for pre-solicitation activities, any Company interactions with CRA, and the selection of proposals. After a proposal for a facility is selected, my team engages Company witness Battaglia's organization who then leads the due diligence and negotiation of the PSA. My team continues to support Mr. Battaglia's organization through its processes and serves as the liaison with CRA as needed.

Q. Other than approval by the Commission, will the acquisitions contemplated in the 2021 Natural Gas Plant RFP require prior authorization from a specific regulatory authority?

A. Yes. The acquisition of generating facilities such as those to be acquired through the 2021 Natural Gas Plant RFP require prior authorization from FERC pursuant to Section 203 of the Federal Power Act ("FPA") and enabling FERC regulations.

Q. How will the Company obtain FERC authorization for the purchase of these plants, which include Company affiliated generation?

A. Section 203 of the FPA provides that FERC will approve an application if FERC finds that the transaction is in the public interest and will not result in cross-subsidization of a non-utility affiliate. The Company will submit one application for each of the transactions contemplated under proposal 1 and proposal 2 to request prior FERC authorization under Section 203 of the FPA. Prior authorization will be required both for the purchase of Covert and the purchase of the generating units owned by subsidiaries of CMS Enterprises.

The Company desired that the RFP be open to all interested parties to increase competition by increasing the number of eligible facilities, including both affiliates and non-affiliates. In addition, since CMS Enterprises, the successful bidder for proposal 2, is a Company affiliate, obtaining FERC authorization for the purchase of the CMS Enterprises' assets (the DIG Plant, Kalamazoo Plant, and Livingston Plant) will require the Company to demonstrate that the transaction is not the result of discriminatory treatment in favor of these affiliates over unaffiliated generators, and that the Company's purchase from a non-rate regulated affiliate will not result in cross-subsidization of the affiliate by the Company. The 2021 Gas Plant RFP was designed to demonstrate both the lack of discriminatory treatment and absence of cross-subsidization in the event an affiliate was a winning bidder.

Q. Please explain the Company's decision to allow affiliates to participate in the 2021 Gas Plant RFP.

A. The Company desired that the RFP be open to all interested parties to increase competition by increasing the number of eligible facilities, which included facilities owned by both affiliates and non-affiliates. The use of the RFP structure described below allowed the Company to broaden the pool of potential bidders while addressing the affiliate-specific concerns noted above.

Q. How does FERC evaluate an affiliate transaction under Section 203 of the FPA?

A. In Section 203 applications that involve the acquisition of an affiliate's assets, FERC applies what are known as the "*Edgar* standards" to ensure that the franchised utility does not favor affiliates over non-affiliates. FERC provides for three ways to demonstrate lack of affiliate abuse under the *Edgar*[12] standards: (1) evidence of direct head-to-head

[12] *Bos. Edison Co. Re: Edgar Elec. Energy Co.*, 55 FERC ¶ 61,382 (1991) ("Edgar").

competition between the affiliate and competing unaffiliated suppliers in a formal solicitation or informal negotiation process; (2) evidence of the prices which non-affiliated buyers were willing to pay; and (3) "benchmark" evidence of the prices, terms and conditions of sales made by nonaffiliated sellers. However, FERC has found that, " [i]n the context of an acquisition of affiliated generation, a competitive solicitation is the most direct and reliable way to ensure no affiliate preference."[13] In addition to demonstrating that an affiliate transaction has not inappropriately favored an affiliate, FERC has found that a competitive solicitation may satisfy the Section 203 requirement that a transaction may not have the effect of subsidizing a non-rate regulated affiliate at the expense of a public utility.[14]

Q. How does FERC evaluate competitive solicitations in the context of affiliate transactions under Section 203?

A. Where a competitive solicitation is used, FERC uses the solicitation guidelines established in *Allegheny Energy Generating Co.*[15] to determine if the competitive solicitation process satisfies the *Edgar* standards. The *Allegheny* solicitation guidelines have four principles:

1. Transparency: the competitive solicitation process should be open and fair;
2. Definition: the product or products sought through the competitive solicitation should be precisely defined;
3. Evaluation: evaluation criteria should be standardized and applied equally to all bids and bidders; and
4. Oversight: an independent third party should design the solicitation, administer bidding, and evaluate bids prior to the company's selection.

[13] *Ameren Energy Generating Co.*, 108 FERC 61.081 at P 67 (2004) ("Ameren").
[14] *See Ohio Power Co.*, 143 FERC ¶ 61,075 at P 29 (2013) (providing that Section 203 applicants may satisfy the cross-subsidization requirements by making an *Ameren* showing).
[15] 108 FERC ¶ 61,082 (2004) ("*Allegheny*").

FERC has recently stated that "[t]he underlying principle when evaluating a competitive solicitation process under the *Edgar[/Allegheny*] criteria is that no affiliate should receive undue preference during any stage of the process."[16] As described in Exhibit A-49 (KGT-5), the CRA Recommendation Letter, the 2021 Gas Plant RFP met the *Allegheny* solicitation guidelines and ensured that no affiliate received any undue preference in that solicitation process. In particular, (i) the "Transparency" principle was satisfied because CRA released the RFP and all relevant information about it to all potential bidders at the same time, (ii) the "Definition" principle was satisfied because the RFP clearly stated all relevant aspects of the product sought, (iii) the "Evaluation" principle was satisfied because the RFP clearly specified the price and non-price criteria under which the bids were evaluated, and (iv) the "Oversight" principle was satisfied because the third party that was employed in the design, administration, and evaluation stages of the RFP process has no financial interest in any of the potential bidders, including CMS Enterprises, or in the outcome of the process and does not own or operate facilities that participate in MISO, the market affected by the RFP.

As required by Section 203 of the FPA, FERC authorization for the transaction will be obtained prior to the closing of the transaction. The Company worked with CRA to ensure that the competitive solicitation would satisfy these guidelines and ultimately comply with FERC's *Edgar/Allegheny* standards. FERC's *Edgar/Allegheny* standards, like the MPSC's Code of Conduct Rules, are intended to ensure that a utility does not harm customers through the utilization of affiliate transactions. Therefore, FERC's approval of the Company's purchase of the affiliate CMS plants will be predicated upon, and will

[16] *See Northern Indiana Pub. Service Co., et al.*, 169 FERC ¶ 61,201 at P 15 (2019).

demonstrate, FERC's conclusion that the transaction "will not harm competition or otherwise be inconsistent with the public interest."

Q. Did participation of the Company's affiliate in the solicitation harm the competitive market?

A. No. The participation of CMS Enterprises did not affect competition in the MISO market, the State of Michigan, or the 2021 Natural Gas Plant RFP. First, the CMS Enterprises' facilities are currently participating in the MISO wholesale electric and capacity markets. The change in ownership from CMS Enterprises to the Company will not have a material effect on the operation or offers of the units into the market as such participation is governed by the MISO Tariff regardless of ownership. Second, the participation of CMS Enterprises in the solicitation will not have an effect on competition in the state of Michigan. CMS Enterprises is a merchant plant operator in the State and does not have a direct relationship with the Company's retail customers. Third, the participation of CMS Enterprises did not cause harm to, and actually increased competition in, the 2021 Natural Gas Plant RFP. The 2021 Natural Gas Plant RFP sought up to 2000 MW UCAP of natural gas plant capacity. As previously explained in my direct testimony, 22 gas plants from 10 different owners were eligible to participate in the RFP, and an RFP advertisement ran in S&P Global Platts Megawatt Daily publication to provide notice of the solicitation. Additionally, CRA proactively reached out to the 10 different owners with expected eligible generators. Every effort was taken to increase participation by eligible bidders in the RFP.

Q. Was the CMS Enterprises' bid in the 2021 Natural Gas Plant RFP competitive?

A. Yes. CRA, the independent RFP Manager, recommended selection of the CMS

Enterprises' bid by Consumers Energy. The CMS Enterprises' bid met the pre-determined qualifying criteria. The project's 25-year NPV, the assets' ages and reliability, and the specific benefits and risks associated with these assets make the proposal 2 bid competitive. The recommendation from CRA was to move forward with both the Covert Plant proposal and the CMS Enterprises proposal based on the evaluation criteria established before proposals were submitted. In fact, the CMS Enterprises' proposal is approximately 30% less expensive on a UCAP basis and 26% less expensive on an ICAP basis compared to the bid by the unaffiliated Covert Plant that was also selected based on CRA's recommendation. As further described in my testimony below, the *total* capital cost of the CMS Enterprises' proposal was also determined to be less than the Company's current embedded *capacity* cost.

Q. The Commission's Code of Conduct Rules require notification of an impending sale of an asset with a market value of $1,000,000 or more between an affiliate and the utility. Has the Commission been notified of the impending sale?

A. Yes. A letter was provided to the director of the regulated energy division of the Commission advising of the impending sale on June 24 , 2021.

Q. Does this purchase comply with the Commission's Code of Conduct requirements involving affiliate asset transfers?

A. Yes. The MPSC's Code of Conduct Rules, Mich Admin Code R 460.10108(4) provide in part that:

> Asset transfers from a utility to an affiliate or other entity within the corporate structure for which the cost is not governed by section 10ee(8) of 2016 PA 341, MCL 460.10ee(8), is at the higher of cost or fair market value. Asset transfers from an affiliate or other entity within the corporate structure to a utility for which the cost is not governed by section 10ee(8) of 2016 PA 341, MCL 460.10ee(8) is

at the lower of cost or fair market value.

The purchase price for the Company's acquisition of the generating plant assets from CMS Enterprises reflects a fair market price for the assets and is lower than the Company's embedded cost of capacity. See Exhibit A-47 (KGT-3). The sale of the CMS Enterprises' generating assets to the Company is not simply a transfer of assets through a standalone negotiation (at a price determined solely by the affiliated entities). Rather, as described above, this transaction was part of the Company's 2021 Natural Gas Plant RFP that was administered by CRA in a competitive and arms-length environment. The use of CRA allowed for and was designed to ensure an independent, fair, and transparent solicitation. It is under this process that CMS Enterprises proposal was selected as an economical and fair market bid. The contract price is lower than the Company's costs, further demonstrating that the transaction is at a fair market price, and at a price that is beneficial to consumers. The Company's proposed purchase therefore complies with the MPSC Code of Conduct.

Q. In determining cost under the Affiliate Transfer provision of the Code of Conduct, is the use of the Company's embedded cost of capacity appropriate?

A. Yes. Utilization of the Company's embedded cost of capacity as cost under the affiliate transfer rule assures that a transaction with an affiliate does not adversely affect the utility's cost structure by causing the cost per unit of service, product, or property to rise above its average or fully embedded cost. In this transaction, the Company is acquiring affiliate-owned resources for the purpose of capacity and the associated energy. Accordingly, to determine if the capacity acquisition is expected to have an impact to customers in the future, the Company must determine what the current cost of capacity is to the customers. The Code of Conduct's comparison of cost to fair market value is to prevent the utility's customers from subsidizing the utility's affiliate. As such, the use of the Company's embedded capacity cost is appropriate.

Q. How did the Company determine its embedded costs of capacity?

A. Exhibit A-47 (KGT-3) provides a detailed calculation of the Company's embedded costs using the costs presented in the Company's most recently approved electric rate case, Case No. U-20697. Total Capacity Related Cost shown on line 1 is the total used in the State Reliability Mechanism calculation presented in that case. The Bundled Test Year Max Demand of 7,052 MW shown on line 2 is sourced from the load forecast that was utilized for Case No. U-20697. Projected Sales and System Output shown on lines 3 and 4, respectively, are also presented in Case No. U-20697. The exhibit shows either the source or formula for each line used to calculate Consumers Energy's embedded capacity cost of $248,951/MW-year that is shown on line 7.

Q. Please provide support that this transaction is at the lower of Consumers Energy's cost or fair market value?

A. Exhibit A-47 (KGT-3) compares the Company's embedded capacity cost to the CMS Enterprises' bid selected. As shown in the Exhibit, the CMS Enterprises' bid price shown on line 10 was lower than the Company's fully allocated embedded cost shown on line 7. Therefore, the fair market value of the assets to be acquired, as determined by the independent RFP and represented by the CMS Enterprises' bid price, is lower than the Company's costs and should be used to determine the approved contract price.

Q. In the alternative, would it be reasonable and appropriate for the Commission to grant a waiver of the Code of Conduct requirements?

A. Yes. In accordance with Mich Admin Code R 460.10111(3), the Commission may grant a waiver of one or more of the Code of Conduct Rules if the granting of the waiver will not impact the development or functioning of the competitive market. The granting of this waiver will not impair the development or functioning of the competitive market as the Company's actions were appropriate because the purchase agreement for the acquisition of the CMS Enterprises' generating assets was made pursuant to a market-based RFP conducted by an independent third party. The contract between the Company and its affiliate resulted from an arms-length negotiation which followed the independently administered RFP selection process. There was no preferential treatment afforded to the affiliate. Customers benefit from the participation of the Company's affiliate in the RFP, and the potential harm which the Code of Conduct was intended to prevent is not present. Additionally, approving the Company's purchase agreement for the acquisition of the affiliate assets would be consistent with the Commission's approvals for Consumers Energy's power purchases from an affiliate granted in the January 27, 2015 Order in Case No. U-17725 and the January 12, 2017 Order in Case No. U-18194 as well as the Commission's approval of DTE Electric Company's acquisition of the East China power plant from that utility's affiliate in the December 11, 2015 Order in Case No. U-17767, page 23.

Q. Was CMS Enterprises afforded preferential treatment as part of the auction process or during the contract negotiation?

A. No. CRA served as an independent third party to administer the 2021 Natural Gas Plant

RFP, which resulted in an arms-length transaction and ensured that there was no preferential treatment or improper information sharing afforded to an affiliate. Participation of affiliates increased the supply available, which led to a greater amount of participation by owners of eligible capacity, thereby increasing competition and benefiting customers. By conducting the 2021 Natural Gas Plant RFP in this manner, the Company satisfies the requirements and the purpose of the Commission's Code of Conduct. In addition, the Company complied with all other aspects of the Code of Conduct in the course of the RFP as well as in negotiating the purchase contract with CMS Enterprises, including the Code of Conduct requirements concerning information sharing, subsidization, and preferential treatment. Consumers Energy did not share any information with CMS Enterprises about the RFP, which was not also provided to other potential bidders, the Company did not and does not subsidize CMS Enterprises and its affiliates, and the Company afforded CMS Enterprises no preferential treatment. The Company's arms-length negotiations with CMS Enterprises resulted in a purchase agreement which is fair, market-based, will benefit customers, and does not negatively affect the market.

Q. Are there other cost recovery considerations for the gas plants that the Company is seeking approval of in this filing?

A. Yes. All of the facilities selected through the 2021 Natural Gas Plant RFP are currently operated by Independent Power Producers ("IPPs"). Accordingly, in the normal course of business, IPPs enter into various forward transactions with buyers for commodities available from the facilities. The bid proposal provided by CMS Enterprises for the DIG, Kalamazoo, and Livingston plants reflected existing commodity sales contracts associated with those plants. These commodities include capacity, energy, and steam. As explained by Company witness Battaglia, the DIG Plant currently has a steam contract with the industrial customers located on the same site as the DIG Plant. Furthermore, the plants included in the CMS Enterprises' bid proposal have committed energy and capacity for sales agreements with third parties. After the acquisition of the DIG, Kalamazoo, and Livingston plants, Consumers Energy will be obligated to honor those contractual commitments, and the revenues from those sales will be used to offset the Company's costs, for the benefit of the Company's customers. The purchase agreement for the acquisition of the DIG, Kalamazoo, and Livingston plants includes minimum capacity amounts required to be available for Consumers Energy at and after closing, and the acquisition purchase price appropriately reflects the third-party contractual commitments described above.

Q. Did the evaluation of the bid including the DIG, Kalamazoo, and Livingston plants include consideration of the commodity sales contracts?

A. Yes. The evaluation of CMS Enterprises' bid proposal took into account the commodity sales contracts attributable to the DIG, Kalamazoo, and Livingston plants. Therefore, the purchase price of the plants appropriately reflects the commodity contracts and the value that those contracts hold.

Q. Will Consumers Energy's bundled customers benefit from the Company's assumption of the commodity sales contracts associated with the DIG, Kalamazoo, and Livingston plants after the approval of the Company's acquisition of the gas plants?

A. Yes. First, as noted above, the purchase price of the plants appropriately reflects the commodity contracts and the value of those contracts. Second, as also noted above, the

Company will recognize the revenue associated with the contracts and use that revenue to offset customer costs. In evaluating CMS Enterprises' bid, CRA modeled the revenue from the forward commodity sales contracts as an offset to the expense of the facility for the NPV analysis. Similarly, the Company has incorporated the future revenues from the forward commodity sales contracts in the IRP evaluation as a credit to general rates. If an opportunity exists to modify or terminate the forward commodity sales contracts that would result in a benefit to customers, the Company will attempt to make such modification or termination.

Q. How does the Company intend to recognize the revenue from the forward commodity sales contracts in future regulatory filings?

A. For the forward capacity sales contracts that the Company would assume, the Company is proposing to treat the revenue received from those contracts as it would treat typical capacity sales revenue received by the Company from the MISO capacity market. With respect to MISO capacity sales, the Company would recognize the revenue received through the sale of capacity in the MISO market through the PSCR mechanism. Therefore, the Company intends to use the same methodology and recognize the capacity revenue of any forward capacity sales contracts through its PSCR mechanism.

Similarly, for the forward energy sales contracts that the Company would assume, the Company is proposing to treat the revenue received from those contracts as it would treat typical energy sales revenue received by the Company from the MISO energy market. With respect to MISO energy sales, the Company would recognize the revenue received through the sale of energy in the MISO market through the PSCR mechanism. Therefore, the Company intends to also recognize the energy revenue of any forward energy sales contracts through its PSCR mechanism.

With respect to the steam contract, the Company does not currently engage in the sale of steam to a host facility. The Company intends to reduce the PSCR recoverable expense by the amount of fuel used to produce the steam sold. The sales revenue for steam and associated fuel cost for steam sales is expected to be recovered through the Company's base rates in an electric rate case proceeding.

SECTION VII: CONCLUSION

Q. Please summarize your direct testimony.

A. In this direct testimony, I have: (i) provided an overview of the key input assumptions in this IRP related to the Company's existing and anticipated PPAs; (ii) provided an overview of the Staff's DG Program proposal and discussed the Company's consideration of that proposal; (iii) detailed the proposed changes to the Company's FCM; (iv) provided an overview of the Company's implementation of PURPA avoided costs and detailed the proposed changes to the Company's PURPA avoided cost implementation; (v) provided an overview of the Company's IRP-based competitive solicitations and detailed the proposed changes to the Company's IRP-based competitive solicitations; (vi) provided an overview of the Company's research on best practices for competitive procurement of renewable PPAs; and (vii) provided an overview of the Company's 2021 Natural Gas Plant RFP.

Q. What approvals does the Company request from the Commission regarding your direct testimony?

A. As explained in my direct testimony, the Company requests the following:

1. Approval to remove the cap on FCM and the applicability of FCM on all future PPAs and PPA amendments;

2. Clarification that the required review of the Company's PURPA avoided cost construct is adequately met through the IRP filings that the Company has agreed to file every three years;

3. Treatment of full avoided cost eligibility for QFs at or below 150 kW in size the same as QFs greater than 150 kW in size;

4. Removal of the requirement to offer to PURPA QFs any remaining capacity from each annual solicitation at full avoided cost rates;

5. Approval to reduce the PURPA Standard Offer Contract and Tariff from 2 MW to 100 kW and replace the current capacity compensation methodology;

6. Approval to offer QFs eligible for full avoided cost rates PPAs with a maximum term length of 20 years;

7. Approval to remove compensation for capacity from the reduced avoided cost rate;

8. Approval to the change the solicitation ownership structure from at least 50% from PPAs and 50% Company-ownership to a structure of at least 50% Company-ownership with the remaining 50% coming from either PPAs or Company-ownership, depending on economics. The proposed ownership structure will also be viewed over the longer term period, as opposed to annually;

9. Approval for additional flexibility in the competitive solicitations by being able to select more or less capacity than the solicited MW target in each annual solicitation and removing the requirement that remaining capacity from each solicitation be made available to PURPA QFs;

10. Confirmation that the Company's proposal to continue seeking approval of PPAs, Company-owned projects, and resets of PURPA full avoided cost rates stemming from competitive solicitations through *ex parte* approval is appropriate; and

11. Approval of the selection and proposed purchase of the DIG, Kalamazoo and Livingston plants by Consumers Energy from its affiliate, CMS Enterprises. The transaction was a result of a competitive solicitation and is compliant with the Commission's Code of Conduct rules. 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, Kalamazoo, and Livingston plants from CMS Enterprises.

12. Approval of any mechanisms necessary to implement these requests.

Q. Does this complete your direct testimony?

A. Yes, it does.

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 Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))))	Case No. U-21090

DIRECT TESTIMONY

OF

NORMAN J. KAPALA

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

Q. Please state your name and business address.

A. My name is Norman J. Kapala, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Executive Director of Fossil and Renewable Generation.

Q. What is your formal education experience?

A. In 1996, I received a Bachelor of Science in Mechanical Engineering from Michigan Technological University. In 2008, I received a Master of Science in Manufacturing Management from Kettering University.

Q. Please describe your business experience.

A. From 1990 to 1994, I served our country as a Rifleman in the United States Marine Corps. In May 1996, I joined Chrysler Corporation and held various positions with progressing levels of responsibility at the Trenton Engine Plant, progressing from a Technical Advisor to Area Manager. In September 2002, I joined Delphi Corporation as a Production Supervisor and, in September 2004, progressed to a Senior Manufacturing Engineer. In July 2008, I joined Consumers Energy at the D.E. Karn ("Karn")/ J.C. Weadock ("Weadock") Generating Complex and progressed through positions from Senior Engineer to the Site Business Manager. In June 2015, I transferred to the B.C. Cobb ("Cobb") Generating Complex and J.H. Campbell ("Campbell") Generating Complex as the Site Business Manager for both facilities. Following the closure of seven of the Company's coal-fired units at its Cobb, Weadock, and J.R. Whiting ("Whiting") sites (collectively, the "Classic 7") in 2016, I was promoted to Executive Director of Coal Generation. In April

2020, I was appointed to the position of Executive Director of Fossil and Renewable Generation with operations and maintenance responsibility for Coal, Gas, Wind, and Solar Generation.

Q. Have you previously sponsored testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I sponsored testimony in the following MPSC cases:

Case No. U-20165	2018 Integrated Resource Plan under MCL 460.6t;
Case No. U-20202	2018 Power Supply Cost Recovery ("PSCR") Reconciliation;
Case No. U-20219	2019 PSCR Plan;
Case No. U-20220	2019 PSCR Reconciliation;
Case No. U-20525	2020 PSCR Plan;
Case No. U-20844	Ludington Depreciation Case;
Case No. U-20802	2021 PSCR Plan; and
Case No. U-20526	2020 PSCR Reconciliation.

Q. What is the purpose of your direct testimony in this proceeding?

A. My direct testimony will address: (i) a description of Consumers Energy's existing generation resources; (ii) the Company's projected capital expenditures and Operations and Maintenance ("O&M") expenses for its existing generation fleet, as those costs were represented in Consumers Energy's Integrated Resource Plan ("IRP") modeling; (iii) the Company's projected capital expenditures and O&M expenses for the Covert combined cycle gas plant ("Covert"), the Dearborn Industrial Generation combined cycle and peaking units ("DIG"), the Kalamazoo River Generating Station peaking plant ("Kalamazoo"), and the Livingston Generating Station peaking plant ("Livingston") that are included in the Company's Proposed Course of Action ("PCA"); (iv) the Company's projected separation activity costs related to the early retirement of its existing generating units at the Campbell and Karn generating sites; (v) Consumers Energy's avoidable and incremental capital expenditures and expenses in different cases involving the early retirement of Campbell Units 1 and 2, Campbell Unit 3, and Karn Units 3 and 4; (vi) the performance of the Company's existing generation fleet; (vii) execution risks faced by Consumers Energy if Campbell Units 1, 2, or 1 and 2, Campbell Unit 3, or Karn Units 3 and 4 are selected for early retirement; and (viii) the tax, community, and employee impacts of an early retirement case.

Q. What is the Company's retirement recommendation with respect to Campbell Units 1 and 2, Campbell Unit 3, and Karn Units 3 and 4?

A. As discussed by several Company witnesses, and as also further explained in my direct testimony, Consumers Energy's PCA proposes to retire Karn Units 3 and 4 in 2023, and retire Campbell Units 1, 2, and 3 in 2025. As discussed in Section II of my testimony, this PCA will result in $75,648,000 in avoided capital expenditures, $15,645,00 in avoided unit separation capital expenditures, and $10,050,000 in avoided major maintenance expenses at Karn Units 3 and 4 compared to the Company's base case outlook ("base case"). In addition, this PCA will result in $190,613,000 in avoided capital expenditures, $64,146,000 in avoided unit separation capital expenditures, and $57,555,000 in avoided major maintenance expenses at Campbell Unit 3; $12,114,000 in avoided capital expenditures and $61,524,000 in avoided major maintenance expenses at Campbell Unit 1; and $13,385,000 in avoided capital expenditures and $84,186,000 in avoided major maintenance expenses at Campbell Unit 2, compared to the Company's base case assumptions of continued operations to the units current design lives in each of the scenarios described by Company witness Sara T. Walz.

Q. Are there any offsets to the avoided cost numbers?

A. Yes. The avoided capital expenditures, avoided unit separation capital expenditures, and avoided major maintenance expenses would be partially offset by the capital expenditures and O&M expenses for the Covert, DIG, Kalamazoo, and Livingston gas generating plants (collectively "new gas plants") which are discussed in Section III of my direct testimony. The Company is also projecting that it will incur approximately $60,000,000 in employee retention and separation activity expenses, as discussed in Section VIII of my direct testimony; however, the Company does not consider these costs incremental in nature as the Company would have incurred these costs at a later date had an early retirement not occurred.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-50 (NJK-1)	Summary of Capital Expenditures and Operations and Maintenance Expenses;
Exhibit A-51 (NJK-2)	Summary of Projected Generation Operations Capital Expenditures;
Exhibit A-52 (NJK-3)	Summary of Projected Generation Operations Major Maintenance Expenses;
Exhibit A-53 (NJK-4)	Summary of Projected Generation Operations Base O&M Expenses;
Exhibit A-54 (NJK-5)	Generation Operations – Summary of Capital Expenditures and Costs of Removal;

Exhibit A-55 (NJK-6)	Summary of Projected Generation Operations Capital Expenditures and Operations and Maintenance Expenses – new gas plants;
Exhibit A-56 (NJK-7)	Summary of Projected Generation Operations Separation Activity Capital Expenditures;
Exhibit A-57 (NJK-8)	Generation Capital Expenses – Avoidable And Incremental Under an Early Retirement Case 2024 - 2032;
Exhibit A-58 (NJK-9)	Generation Major Maintenance Expenses – Avoidable Under An Early Retirement Case 2024-2032;
Exhibit A-59 (NJK-10)	Generating Unit Random Outage Rates; and
Confidential Exhibit A-60 (NJK-11)	Generating Unit Heat Rates.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

SECTION I: EXISTING GENERATION RESOURCES

Q. Please provide an overview of the Company's non-renewable energy generation assets.

A. As of 2020, the Company's total non-renewable owned generation assets had a net demonstrated summer operating capability of 5,292 MW, comprised of the following coal-, oil-, or gas-fired; hydroelectric; and pumped storage facility units:

TABLE 1

RESOURCE	MICHIGAN LOCATION	IN-SERVICE DATE	AGE (years)	RETIREMENT DATE	REMAINING EST. TIME OF OPERATION (years)	LICENSING STATUS	NET GENERATING CAPABILITY (MW)
COAL FIRED							
JH Campbell 1	West Olive, MI	1962	59	2031	10	Active	260
JH Campbell 2	West Olive, MI	1967	54	2031	10	Active	260
JH Campbell 3	West Olive, MI	1980	41	2039	18	Active	785 (owned share)
DE Karn 1	Essexville, MI	1959	62	2023	2	Active	255
DE Karn 2	Essexville, MI	1961	60	2023	2	Active	258
OIL OR GAS FIRED							
DE Karn 3	Essexville, MI	1975	46	2031	10	Active	362
DE Karn 4	Essexville, MI	1977	44	2031	10	Active	362
Zeeland CC	Zeeland, MI	2002	19	2041	20	Active	575
Zeeland 1A	Zeeland, MI	2002	19	2041	20	Active	180
Zeeland 1B	Zeeland, MI	2002	19	2041	20	Active	180
Jackson	Jackson, MI	2002	19	2041	20	Active	547
HYDROELECTRIC							
Alcona	Alcona County, MI	1924	97	n/a	n/a	Active	8
Allegan	Allegan County, MI	1936	85	n/a	n/a	Active	3
Cooke	Iosco County, MI	1911	110	n/a	n/a	Active	9
Croton	Newaygo County, MI	1907	114	n/a	n/a	Active	9
Five Channels	Iosco County, MI	1912	109	n/a	n/a	Active	6
Foote	Iosco County, MI	1918	103	n/a	n/a	Active	9
Hardy	Newaygo County, MI	1931	90	n/a	n/a	Active	30
Hodenpyl	Wexford County, MI	1925	96	n/a	n/a	Active	17
Loud	Iosco County, MI	1913	108	n/a	n/a	Active	4
Mio	Oscoda County, MI	1916	105	n/a	n/a	Active	5
Rogers	Mecosta County, MI	1906	115	n/a	n/a	Active	7
Tippy	Manistee County, MI	1918	103	n/a	n/a	Active	21
Webber	Ionia County, MI	1907	114	n/a	n/a	Active	3
ENERGY STORAGE							
Ludington Units 1-6	Ludington, MI	1973	48	2069	48	Active	1138 (owned share)

Q. What does "owned share" mean when used with respect to Campbell Unit 3?

A. The Company owns approximately 93% of Campbell Unit 3. Michigan Public Power Agency and Wolverine Power Supply Cooperative, Inc. own the remaining 7%. Thus, the 785 MW capacity reported is 93% of the Campbell Unit 3 net demonstrated summer operating capability, reflecting the Company's share of ownership.

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

A. The Company owns 51% of the Ludington Plant and DTE Electric Company owns the remaining 49%. Thus, the 1,138 MW capacity reported is 51% of the total Ludington Plant net demonstrated summer operating capability, reflecting the Company's share of ownership.

SECTION II: PROJECTED CAPITAL EXPENDITURES AND O&M EXPENSES OF EXISTING GENERATION FLEET

Q. Please explain Exhibit A-50 (NJK-1).

A. Exhibit A-50 (NJK-1) shows the projected capital expenditures and major maintenance expenses for the Campbell Units 1, 2, and 3; Karn Units 1 and 2; and Karn Units 3 and 4 for the period of January 1, 2020 through May 31, 2031, and the base O&M expenses for the Campbell Units 1, 2, and 3; Karn Units 1 and 2; and Karn Units 3 and 4 for the same period, under a variety of cases. These are the costs and the date range that the Company used for modeling purposes in this IRP. The Company evaluated a base case, in which all four units (Karn Units 3 and 4 and Campbell Units 1 and 2) retire on May 31, 2031, and then evaluated sixteen early retirement cases related to the Karn and Campbell sites:

- Retirement of Karn Units 3 and 4 on May 31, 2023;
- Retirement of Karn Units 3 and 4 on May 31, 2025;
- Retirement of Campbell Unit 3 on May 31, 2025;
- Retirement of Campbell Unit 3 on May 31, 2032;
- Retirement of Campbell Unit 1 on May 31, 2024;
- Retirement of Campbell Unit 1 on May 31, 2025;
- Retirement of Campbell Unit 1 on May 31, 2026;

- Retirement of Campbell Unit 1 on May 31, 2028;
- Retirement of Campbell Unit 2 on May 31, 2024;
- Retirement of Campbell Unit 2 on May 31, 2025;
- Retirement of Campbell Unit 2 on May 31, 2026;
- Retirement of Campbell Unit 2 on May 31, 2028;
- Retirement of Campbell Units 1 and 2 on May 31, 2024;
- Retirement of Campbell Units 1 and 2 on May 31, 2025;
- Retirement of Campbell Units 1 and 2 on May 31, 2026; and
- Retirement of Campbell Units 1 and 2 on May 31, 2028.

Q. Please explain Exhibit A-50 (NJK-1), pages 1 and 2.

A. Exhibit A-50 (NJK-1), pages 1 and 2, presents the total capital expenditures projected to be made at the Karn and Campbell sites by the Company in each of the sixteen cases listed above. With the exception of Campbell Unit 3, the capital expenditure amounts presented for each unit in each case is a total of all capital expenditures for the period of January 1, 2020 through May 31, 2031. The capital expenditure amounts for Campbell Unit 3 reflect projected amounts through May 31, 2039. For each of the sixteen early retirement cases, the exhibit presents both the total capital expenditures (including unit separation) over that period that would be made in each respective case and the difference in capital expenditures over that period relative to the base case. Exhibit A-50 (NJK-1), page 1, lines 2 and 3 reflects the early retirement cases for Karn Units 3 and 4; for these cases, the capital expenditures for Karn Units 3 and 4 are reduced versus those shown in the base case. As shown in Exhibit A-50 (NJK-1), page 1, lines 2 and 3, columns (b) and (c), the 2023 retirement case results in both reduced capital expenditures and also reduced separation costs at Karn Units 3 and 4, and the 2025 retirement case results in reduced capital expenditures at Karn Units 3 and 4, which will be discussed later in my direct testimony. Likewise, Exhibit A-50 (NJK-1), page 1, lines 4 and 5, reflects the early retirement cases for Campbell Unit 3; for each of these cases, both the capital expenditures and separation costs for Campbell Unit 3 are also reduced from those shown in the base case. Exhibit A-50 (NJK-1), pages 1-2, lines 6 through 17, reflects the retirement cases for which Campbell Unit 1 retires, Campbell Unit 2 retires, or both Campbell Units 1 and 2 retire. Exhibit A-50 (NJK-1), pages 1 and 2, lines 6 through 13, columns (c) and (d), shows the reduced or incremental costs for Campbell Units 1 and 2 versus the base case for the individual unit retirements. Exhibit A-50 (NJK-1), page 2, lines 14 through 17, columns (c) and (d), show reduced costs at Campbell Units 1 and 2 when both units retire. No incremental costs are projected at Campbell Unit 3 versus the base case for the cases in which Campbell Units 1 and 2 both retire. Costs of removal are not included in any of the cases in Exhibit A-50 (NJK-1), page 1, nor are environmental costs related to Steam Electric Effluent Guidelines ("SEEG") and Clean Water Act Section 316(b) ("316(b)"). Those environmental costs are discussed by Company witness Heather A. Breining.

Q. Please explain Exhibit A-50 (NJK-1), pages 3 and 4.

A. Exhibit A-50 (NJK-1), pages 3 and 4, presents the total major maintenance expenses projected to be made at the Karn and Campbell sites by the Company in each of the sixteen cases listed above. With the exception of Campbell Unit 3, the major maintenance expenses presented for each unit in each case is a total of all major maintenance expenses for the period of January 1, 2020 through May 31, 2031. The major maintenance expenses for Campbell Unit 3 reflect projected amounts through May 31, 2039. For each of the 16 early retirement cases, the exhibit presents both the total major maintenance expenses over that period that would be made in each respective case, and the difference in major maintenance expenses over that period relative to the base case. Exhibit A-50 (NJK-1), page 3, lines 2 and 3, reflects the early retirement cases for Karn Units 3 and 4; for these cases, the major maintenance expenses for Karn Units 3 and 4 are reduced from those shown in the base case. Likewise, Exhibit A-50 (NJK-1), page 3, lines 4 and 5, reflects the early retirement cases for Campbell Unit 3; for each of these cases, the major maintenance expenses for Campbell Unit 3 are also reduced from those shown in the base case. Exhibit A-50 (NJK-1), pages 3 and 4, lines 6 through 17, reflects the retirement cases for which Campbell Unit 1 retires, Campbell Unit 2 retires, or both Campbell Units 1 and 2 retire. Exhibit A-50 (NJK-1), pages 3 and 4, lines 6 through 13, columns (c) and (d), shows the reduced major maintenance expenses for Campbell Units 1 and 2 versus the base case for the individual unit retirements. Exhibit A-50 (NJK-1), page 2, lines 14 through 17 columns (c) and (d), shows reduced costs at Campbell Units 1 and 2 when both units retire. No incremental major maintenance expenses are projected at Campbell Unit 3 versus the base case for the cases in which Campbell Units 1 and 2 both retire. Exhibit A-50 (NJK-1), pages 3 and 4, does not include environmental costs related to SEEG and Clean Water Act Section 316(b) ("316(b)"). Those environmental costs are discussed by Company witness Breining.

Q. Please explain Exhibit A-50 (NJK-1), pages 5 and 6.

A. Exhibit A-50 (NJK-1), pages 5 and 6, presents the total O&M expenses projected to be made at the Karn and Campbell sites by the Company in each of the sixteen cases listed above. With the exception of Campbell Unit 3, the O&M expenses presented for each unit in each case is a total of all O&M expenses for the period of January 1, 2020 through May 31, 2031. The O&M expenses for Campbell Unit 3 reflect projected amounts through May 31, 2039. For each of the 16 early retirement cases, the exhibit presents both the total O&M expenses over that period that would be made in each respective case and the difference in O&M expenses over that period relative to the base case. Exhibit A-50 (NJK-1), page 5, lines 2 and 3, reflects the early retirement cases for Karn Units 3 and 4; for these cases, the O&M expenses for Karn Units 3 and 4 are reduced from those shown in the base case. Likewise, Exhibit A-50 (NJK-1), page 5, lines 4 and 5, reflects the early retirement cases for Campbell Unit 3; for each of these cases, the O&M expenses for Campbell Unit 3 are also reduced from those shown in the base case. Exhibit A-50 (NJK-1), pages 5 and 6, lines 6 through 17, reflects the retirement cases for which Campbell Unit 1 retires, Campbell Unit 2 retires, or both Campbell Units 1 and 2 retire. Exhibit A-50 (NJK-1), pages 5 and 6, lines 6 through 9, columns (c), (d), and (e), shows the reduced O&M expenses for Campbell Unit 1 retirement and increased O&M expenses for Campbell Units 2 and 3 versus the base case for the individual unit retirements. Exhibit A-50 (NJK-1), pages 5 and 6, lines 10 through 13, columns (c), (d), and (e), shows the reduced O&M expenses for Campbell Unit 2 retirement and increased O&M expenses for Campbell Units 1 and 3 versus the base case for the individual unit retirements. Exhibit A-50 (NJK-1), page 2, lines 14 through 17, columns (c), (d), and (e), shows the reduced O&M expenses for Campbell Units 1 and 2 when both units retire and increased O&M expenses for Campbell Unit 3. Exhibit A-50 (NJK-1), pages 5 and 6 do not include environmental costs related to SEEGand Clean Water Act Section 316(b) ("316(b)"). Those environmental costs are discussed by Company witness Breining.

Q. Please explain Exhibit A-51 (NJK-2), page 1.

A. Exhibit A-51 (NJK-2), page 1, shows the Company's projected capital expenditures for the Company's generating units at the Campbell and Karn sites for each calendar year over the period from January 1, 2020 through May 31, 2039 in the base case retirement case. In this case, Karn Units 1 and 2 retire on May 31, 2023, Karn Units 3 and 4 and Campbell Units 1 and 2 retire on May 31, 2031, and Campbell Unit 3 retires on May 31, 2039.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2), page 1, line 1?

A. The capital expenditures in Exhibit A-51 (NJK-2), page 1, line 1, are those that were used for 2020 in the Company's IRP modeling.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2), page 1, line 2?

A. In 2021, the Company projects to spend:

- $2,859,236 at Karn Units 1 and 2, covering seventeen projects, none of which exceed $500,000;
- $4,172,000 at Karn Units 3 and 4, including:
  - Auxiliary Boiler System Optimization ($2,000,000);
  - Replace House Service Water Screen Drives ($950,000); and
  - Twenty-seven additional projects totaling $1,222,000, with no individual project exceeding $300,000;
- $3,493,440 at Campbell Unit 1, including:
  - Re-align 4160V switchgear with Air Quality Control System ("AQCS") implementation ($1,000,000); and
  - Eleven additional projects totaling $2,493,440, with no individual project exceeding $696,000;
- $13,512,160 at Campbell Unit 2, including:

- Low Pressure Turbine Overhaul ($3,500,000);
- Secondary Air Heater Basket and Seal Replacement ($1,750,000);
- Pulse Jet Fabric Filter ("PJFF") Bag Replacement ($2,394,000); and
- Seventeen additional projects totaling $5,868,160, with no individual project exceeding $858,100; and

- $19,576,382 at Campbell Unit 3, including:
  - Selective Catalytic Reduction ("SCR") Reactor Catalyst Management ($1,959,510);
  - Replace CO-O2 Monitors ($1,044,600);
  - Mill Complete Overhauls ($1,235,000);
  - Reheater Sootblower ($1,250,000);
  - Sootblowing Air Upgrade ($1,200,000);
  - Replace Lake Michigan Intake Screens ($1,339,000);
  - Cell Construction and Permitting ($5,482,830); and
  - Twenty-two additional projects totaling $6,06,442, with no individual project exceeding $750,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2), page 1, line 3?

A. In 2022, the Company projects to spend

- $2,135,136 at Karn Units 1 and 2, covering 12 projects, none of which exceeds $350,000;
- $15,416,000 at Karn Units 3 and 4, including:
  - Tank Farm Storage Tank Heating Lines ($1,400,000);
  - Karn Sync Wire Replacement ($1,320,000);
  - Auxiliary Boiler System Optimization ($1,160,000);
  - Parking Lot Replacement ($1,000,000);
  - Karn 3 Ductwork Expansion Joint Replacement ($3,000,000);

  - Karn 3 Cooling Tower Rebuild ($2,500,000); and
  - Twenty-two additional projects totaling $5,036,000, with no individual project exceeding $450,000;
- $7,300,000 at Campbell Unit 1, including:
  - PJFF Bag Replacement ($1,578,000);
  - Superheat Outlet Pendant – partial replacement ($3,490,000); and
  - Five additional projects totaling $2,232,000, with no individual project exceeding $750,000;
- $5,256,500 at Campbell Unit 2, including:
  - Catalyst Management ($1,120,000);
  - Replace Burner Assemblies ($1,350,000); and
  - Six additional projects totaling $2,786,500, with no individual project exceeding $836,500; and
- $17,125,333 at Campbell Unit 3, including:
  - 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); and
  - Sixteen additional projects totaling $6,047,032, with no individual project exceeding $889,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2), page 1, line 4?

A. In 2023, the Company projects to spend:

- $1,123,678 at Karn Units 1 and 2, covering 12 projects, none of which exceeds $235,136;

- $10,072,000 at Karn Units 3 and 4, including:
  - Distributed Control System Evergreen Project ($1,000,000);
  - Karn 3 Ductwork Expansion Joint Replacement ($1,000,000);
  - Karn 3 Cooling Tower Rebuild ($4,800,000);
  - Capital Equipment Repairs ($1,000,000); and
  - Twelve additional projects totaling $2,272,000, with no individual project exceeding $758,000;
- $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); and
  - Twelve additional projects totaling $2,087,180, with no individual project exceeding $750,000;
- $9,472,020 at Campbell Unit 2, including:
  - Horizontal Reheat Replacement ($5,053,000);
  - SCR Reactor Catalyst Replacement ($2,000,000); and
  - Nine additional projects totaling $2,419,020, with no individual project exceeding $750,000; and
- $20,766,757 at Campbell Unit 3, including:
  - 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); and

- Eighteen additional projects totaling $7,242,827, with no individual project exceeding $750,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2), page 1, line 5?

A. In 2024, the Company projects to spend:

- $9,775,000 at Karn Units 3 and 4, including:
  - Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack ($800,000);
  - Karn 3 Cooling Tower Rebuild ($4,950,000);
  - Capital Equipment Repairs ($3,000,000); and
  - Twelve additional projects totaling $2,272,000, with no individual project exceeding $758,000;
- $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) and
  - Six additional projects totaling $1,415,900, with no individual project exceeding $815,900;
- $11,252,000 at Campbell Unit 2, including:
  - Horizontal Reheat Replacement ($7,952,000);
  - Distributed Control System and Simulator Upgrade ($1,500,000); and
  - Four additional projects totaling $1,800,000, with no individual project exceeding $750,000; and
- $35,780,799 at Campbell Unit 3, including:
  - 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);
- Dry Ash Landfill Closure ($1,635,230);
- Cell Construction and Permitting ($5,482,830); and
- Twenty-two additional projects totaling $10,600,029, with no individual project exceeding $933,100.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2), page 1, line 6?

A. In 2025, the Company projects to spend:

- $10,134,000 at Karn Units 3 and 4, including:
  - Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack ($2,500,000);
  - Karn 3 Cooling Tower Rebuild ($2,565,000);
  - Capital Replacements ($4,000,000); and
  - Three additional projects totaling $1,069,000, with no individual project exceeding $750,000;
- $2,550,000 at Campbell Unit 1, including four projects that do not exceed $669,000 individually; and
- $7,800,000 at Campbell Unit 2, including:
  - Replace turbine right side Reheat Stop Valve body ($1,850,000); and
  - Boiler Component Replacement ($3,000,000);
- Five additional projects totaling $2,950,000, with no individual project exceeding $750,000; and
- $30,179,045 at Campbell Unit 3, including:

- GSU Replacement ($6,485,045);
- SCR Reactor Catalyst Management ($3,000,000);
- AQCS Equipment repair/replacement ($1,000,000);
- Part 115 JH Campbell B-K landfill cap ($15,667,000)
- Cell Construction and Permitting ($2,000,000); and
- Four additional projects totaling $2,027,000, with no individual project exceeding $750,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2), page 1, line 7?

A. In 2026, the Company projects to spend:

- $9,900,000 at Karn Units 3 and 4, including:
  - Karn 3 Ductwork Replace Insulation & Lagging - ID Fan to Stack ($4,000,000);
  - Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack ($3,000,000);
  - Capital Replacements ($2,000,000); and
  - Three additional projects totaling $6,050,000, with no individual project exceeding $250,000;
- $3,300,000 at Campbell Unit 1, including five projects that do not exceed $750,000 individually;
- $4,420,000 at Campbell Unit 2, including:
  - Catalyst Management ($1,120,000); and
  - Five additional projects totaling $3,300,000, with no individual project exceeding $750,000; and
- $29,053,000 at Campbell Unit 3, including:
  - Replace Air and Flue Gas Expansion Joints ($2,000,000);
  - Part 115 JH Campbell B-K landfill cap ($24,653,000); and

- Four additional projects totaling $2,400,000, with no individual project exceeding $750,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2), page 1, lines 8 through 20?

A. In each year from 2027 through 2039 in the base case, the Company projects to incur capital expenditures at Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3, as shown in Exhibit A-51 (NJK-2), page 1. The capital projects for Karn Units 3 and 4 are as follows:

- 2027: Four projects totaling $8,950,000, which includes:
  - K3 Ductwork Replace Insulation & Lagging - ID Fan to Stack ($2,600,000);
  - Karn 3 Distributed Control System ("DCS") & Simulator Evergreen ($1,000,000);
  - Karn 4 DCS & Simulator Evergreen ($1,350,000); and
  - Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack ($4,000,000);
- 2028-2029: One project each year totaling $2,000,000, for capital replacements;
- 2030: One project totaling $1,000,000, for capital replacements; and
- 2031: One project totaling $500,000, for capital replacements.

The capital projects for Campbell Unit 1 are as follows:

- 2027: Five projects totaling $4,050,000, which include:
  - DCS and Simulator Upgrade ($1,500,000); and
  - Four additional projects totaling $2,550,000, with no individual project exceeding $750,000;
- 2028: Four projects totaling $3,500,000, which include:
  - Fuel Handling and Infrastructure Replacements ($1,000,000);
  - AQCS Equipment Repair/Replacement ($1,000,000); and

  - Two additional projects totaling $1,500,000, with no individual project exceeding $750,000;

- 2029: Five projects totaling $3,878,000, which includes:
  - PJFF Filter Bag Replacement ($1,578,000);
  - AQCS Equipment repair/replacement ($1,000,000); and
  - Three additional projects totaling $1,300,000, with no individual project exceeding $500,000;
- 2030: Five projects totaling $2,563,000, which include:
  - PJFF Filter Bag Replacement ($1,513,600); and
  - Four additional projects totaling $1,050,000, with no individual project exceeding $300,000; and
- 2031: One Project totaling $250,000.

The capital projects for Campbell Unit 2 are as follows:

- 2027: Eight projects totaling $6,845,000, which include:
  - Catalyst Management ($2,806,000);
  - PJFF bag replacement ($1,389,000); and
  - Six projects totaling $2,650,000 with no individual project which exceeds $750,000;
- 2028: Six projects totaling $7,394,000, which include;
  - DCS and Simulator Upgrade ($1,500,000);
  - PJFF bag replacement ($1,389,000);
  - Fuel Handling and Infrastructure Replacements ($1,000,000);
  - AQCS Equipment repair/replacement ($1,000,000); and
  - Two projects totaling $1,500,000 with no individual project which exceeds $500,000;
- 2029: Five projects totaling $2,500,000, which include;
  - AQCS Equipment repair/replacement ($1,000,000); and

    - Four projects totaling $1,894,333 with no individual project which exceeds $500,000;

- 2030: Four projects totaling $1,050,000, with no individual project which exceeds $300,000; and

- 2031: One project totaling $250,000.

The capital projects for Campbell Unit 3 are as follows:

- 2027: Six projects totaling $30,563,600, including:
    - Cell Construction and Permitting ($3,500,000);
    - Part 115 JH Campbell B-K landfill cap ($24,663,000); and
    - Four additional projects totaling $2,400,000, with no individual project exceeding $750,000;

- 2028: Five projects totaling $4,400,000, including:
    - SCR Reactor Catalyst Management ($2,000,000); and
    - Four additional projects totaling $2,400,000, with no individual project exceeding $750,000;

- 2029: Six projects totaling $11,750,000, which include:
    - SCR Reactor Catalyst Management ($3,000,000);
    - Boiler Component Replacement ($5,000,000);
    - AQCS Equipment repair/replacement ($2,000,000); and
    - Three additional projects totaling $1,750,000, with no individual project exceeding $750,000;

- 2030: Four projects totaling $4,650,000, which include:
    - SCR Reactor Catalyst Management ($3,000,000);
    - AQCS Equipment repair/replacement ($3,000,000); and
    - Three additional projects totaling $1,650,000, with no individual project exceeding $750,000;

- 2031: Four projects totaling $2,400,000, with no individual project which exceeds $750,000;

- 2032: Four projects totaling $2,750,000, which include:
    - AQCS Equipment repair/replacement ($1,000,000); and
    - Three additional projects totaling $1,750,000, with no individual project exceeding $750,000;
- 2033: Seven projects totaling $11,750,000, which include:
    - SCR Reactor Catalyst Management ($2,000,000);
    - Replace Air and Flue Gas Expansion Joints ($2,000,000);
    - Boiler Component Replacement ($5,000,000);
    - AQCS Equipment Repair/Replacement ($1,000,000); and
    - Three additional projects totaling $1,750,000, with no individual project exceeding $750,000;
- 2034: Five projects totaling $5,400,000, which include:
    - SCR Reactor Catalyst Management ($3,000,000); and
    - Four additional projects totaling $2,400,000, with no individual project exceeding $750,000;
- 2035: our projects totaling $3,650,000, which include:
    - AQCS Equipment repair/replacement ($2,000,000); and
    - Three additional projects totaling $1,650,000, with no individual project exceeding $750,000;
- 2036: Four projects totaling $4,650,000, which include:
    - AQCS Equipment repair/replacement ($3,000,000); and
    - Three additional projects totaling $1,650,000, with no individual project exceeding $750,000;
- 2037: Four projects totaling $2,400,000, with no individual project which exceeds $750,000; and
- 2038: Two projects totaling $550,600, with no individual project which exceeds $300,000.

Q. Please explain Exhibit A-51 (NJK-2), page 2.

A. Exhibit A-51 (NJK-2), page 2, shows the Company's projected capital expenditures for Karn Units 3 and 4 for the cases in which Karn Units 3 and 4 retire on May 31, 2023 or May 31, 2025. As shown in Exhibit A-51 (NJK-2), page 2, column (c), there are no projected incremental capital expenditures for Karn Units 1 and 2 in these cases, which are discussed later in my direct testimony. The projected capital expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2), page 2, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2), page 2, line 13, column (d), shows that the Company would avoid $75,648,000 in capital expenditures if Karn Units 3 and 4 are retired on May 31, 2023. Exhibit A-51 (NJK-2), page 2, line 13, column (i), shows that the Company would avoid $62,987,000 in capital expenditures if Karn Units 3 and 4 are retired on May 31, 2025. Exhibit A-51 (NJK-2), page 2, line 13, columns (e) and (j), shows that the Company would avoid $15,465,000 in unit separation capital expenditures and $9,161,000 in unit separation capital expenditures if Karn Units 3 and 4 are retired on May 31, 2023 and May 31, 2025 respectively.

Q. Please explain Exhibit A-51 (NJK-2), page 3.

A. Exhibit A-51 (NJK-2), page 3, shows the Company's projected capital expenditures for Campbell Unit 3 for the cases in which Campbell Unit 3 retires on May 31, 2025 or on May 31, 2032. The projected capital expenditures are shown for each calendar year from January 1, 2020 through May 31, 2039. Exhibit A-51 (NJK-2), page 3, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2), page 3, line 21, columns (c) and (d), show that the Company would avoid $190,613,000 in capital expenditures and $64,146,000 in unit separation capital expenditures if Campbell Unit 3 is retired on May 31, 2025. Exhibit A-51 (NJK-2), page 3, line 21, columns (g) and (h), shows that the Company would avoid $31,400,000 in capital expenditures and $64,146,000 in unit separation capital expenditures if Campbell Unit 3 is retired on May 31, 2032. Campbell Units 1 and 2 are not reflected in Exhibit A-51 (NJK-2), page 3, because the Campbell Unit 3 early retirement case assumes that Campbell Units 1 and 2 retire in a similar timeframe and, therefore, have identical costs to those in the base case through 2026 and 2032.

Q. Please explain Exhibit A-51 (NJK-2), page 4.

A. Exhibit A-51 (NJK-2), page 4, shows the Company's projected capital expenditures for Campbell Units 1 and 2 for the cases in which Campbell Unit 1 retires on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2), page 4, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2), page 4, line 13, columns (d) and (e), shows that the Company would avoid $42,840,000 in capital expenditures if Campbell Unit 1 is retired on May 31, 2024 and Campbell Unit 2 would incur incremental capital expenditures of $253,000. Exhibit A-51 (NJK-2), page 4, line 13, columns (i) and (j), show that the Company would avoid $35,951,000 in capital expenditures at Campbell Unit 1 and incur no incremental capital expenditures at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2025. Exhibit A-51 (NJK-2), page 4, line 26, columns (d) and (e), shows that the Company would avoid $34,046,000 in capital expenditures at Campbell Unit 1 and incur no incremental capital expenditures at Campbell Unit 2 if Campbell Unit 1 is retired on

May 31, 2026. Exhibit A-51 (NJK-2), page 4, line 26, columns (i) and (j), shows that the Company would avoid $14,442,000 in capital expenditures at Campbell Unit 1 and incur no incremental capital expenditures at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-51 (NJK-2), page 4, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 capital expenditures as it is assumed that unit separation capital expenditures reflected in the base case are not avoided.

Q. Please explain Exhibit A-51 (NJK-2), page 5.

A. Exhibit A-51 (NJK-2), page 5, shows the Company's projected capital expenditures for Campbell Units 1 and 2 for the cases in which Campbell Unit 2 retires on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2), page 5, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2), page 5, line 13, columns (d) and (e), shows that the Company would avoid $56,070,000 in capital expenditures if Campbell Unit 2 is retired on May 31, 2024, and Campbell Unit 1 would incur incremental capital expenditures of $322,000. Exhibit A-51 (NJK-2), page 5, line 13, columns (i) and (j), shows that the Company would avoid $46,573,000 in capital expenditures at Campbell Unit 2 and incur no incremental capital expenditures at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2025. Exhibit A-51 (NJK-2), page 4, line 26, columns (d) and (e), shows that the Company would avoid $45,273,000 in capital expenditures at Campbell Unit 2 and incur no incremental capital expenditures at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2026. Exhibit A-51 (NJK-2), page 4, line 26, columns (i) and (j), shows that the

Company would avoid $18,333,000 in capital expenditures at Campbell Unit 2 and incur no incremental capital expenditures at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-51 (NJK-2), page 5, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 capital expenditures as it is assumed that unit separation capital expenditures reflected in the base case are not avoided.

Q. Please explain Exhibit A-51 (NJK-2), page 6.

A. Exhibit A-51 (NJK-2), page 6, shows the Company's projected capital expenditures for Campbell Units 1 and 2 for the cases in which both Campbell Units 1 and 2 retire on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected capital expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2), page 6, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2), page 6, line 13, columns (d) and (e), shows that the Company would avoid $42,840,000 in capital expenditures at Campbell Unit 1 and $56,070,000 in capital expenditures at Campbell Unit 2 if both units are retired on May 31, 2024. Exhibit A-51 (NJK-2), page 6, line 13, columns (i) and (j), shows that the Company would avoid $35,951,000 in capital expenditures at Campbell Unit 1 and $46,573,000 in capital expenditures at Campbell Unit 2 if both units are retired on May 31, 2025. Exhibit A-51 (NJK-2), page 6, line 26, columns (d) and (e), shows that the Company would avoid $34,046,000 in capital expenditures at Campbell Unit 1 and $45,273,000 in capital expenditures at Campbell Unit 2 if both units are retired on May 31, 2026. Exhibit A-51 (NJK-2), page 6, line 26, columns (i) and (j), shows that the Company would avoid $14,442,000 in capital expenditures at Campbell Unit 1 and $18,333,000 in capital expenditures at Campbell Unit 2 if both units are retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-51 (NJK-2), page 5, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 capital expenditures because the unit separation capital expenditures reflected in the base case are not avoided.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 1?

A. The major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 1, are those that were used for 2020 in the Company's IRP modeling.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 2?

A. In 2021, the Company projects to spend:

- $3,771,000 at Karn Units 1 and 2, covering 21 projects, none of which exceeds $700,000;
- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceeds $250,000;
- $11,930,200 at Campbell Units 1 and 2 including:
    - Campbell 2 Generator Overhaul-Rewedge-Collector Ring Replacement ($3,630,000);
    - Campbell 2 Turbine Inspection and Overhaul ($2,370,000);
    - Campbell 1 and 2 Periodic Outage Maintenance ($1,512,000); and
    - Twenty-two additional projects totaling $4,418,200, with no individual project exceeding $750,000; and
- $5,102,729 at Campbell Unit 3 including:
    - Campbell 3 Turbine Valve Inspection ($1,200,000); and
    - Twenty-two additional projects totaling $3,902,729, with no individual project exceeding $715,000.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 3?

A. In 2022, the Company projects to spend:

- $3,292,000 at Karn Units 1 and 2, covering 19 projects, none of which exceeds $700,000;
- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceed $250,000;
- $3,537,000 at Campbell Units 1 and 2 including:
  - Campbell 1 and 2 Periodic Outage Maintenance ($1,248,000); and
  - Thirteen additional projects totaling $2,289,000, with no individual project exceeding $600,000; and
- $4,208,040 at Campbell Unit 3 including:
  - Boiler Feed Pump Turbine Inspection ($1,680,000); and
  - Fourteen additional projects totaling $2,528,040, with no individual project exceeding $425,000.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 4?

A. In 2023, the Company projects to spend:

- $826,000 at Karn Units 1 and 2, covering seven projects, none of which exceeds $200,000;
- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceeds $250,000;
- $2,905,000 at Campbell Units 1 and 2 covering 10 projects, none of which exceeds $643,667; and
- $2,523,970 at Campbell Unit 3 covering 12 projects, none of which exceeds $425,000.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 5?

A. In 2024, the Company projects to spend:

- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceeds $250,000;
- $3,405,167 at Campbell Units 1 and 2 covering 12 projects, none of which exceeds $655,167; and
- $12,954,250 at Campbell Unit 3 including:
    - 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); and
    - Eight additional projects totaling $1,660,800, with no individual project exceeding $430,000.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 6?

A. In 2025, the Company projects to spend:

- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceeds $250,000;
- $4,569,000 at Campbell Units 1 and 2 including:
    - Campbell 2 Turbine Valve Inspection ($1,300,000); and
    - Seven additional projects totaling $3,269,000, with no individual project exceeding $666,667; and

- $3,810,600 at Campbell Unit 3 including:
  - Campbell 3 Turbine Valve Inspection ($1,200,000);
  - Campbell 3 Base Outage Boiler and Critical Maintenance ($1,100,000); and
  - Six additional projects totaling $1,410,600, with no individual project exceeding $450,000.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 7?

A. In 2026, the Company projects to spend:

- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceed $250,000;
- $3,541,000 at Campbell Units 1 and 2 covering nine projects, none of which exceed 678,167; and
- $1,660,600 at Campbell Unit 3 covering five projects, none of which exceed 500,000.

Q. What is the basis for the projected expenses in Exhibit A-52 (NJK-3), page 1, lines 8 through 20?

A. In each year from 2027 through 2039 in the base case, the Company projects to incur major maintenance expenses at Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3, as shown in Exhibit A-52 (NJK-3), page 1. The number of individual major maintenance projects for Karn Units 3 and 4 is as follows:

- 2027: Seven projects totaling $1,000,000, with no individual project which exceeds $250,000;
- 2028: Seven projects totaling $1,000,000, with no individual project which exceeds $250,000;
- 2029: Seven projects totaling $1,000,000, with no individual project which exceeds $250,000;
- 2030: Seven projects totaling $800,000, with no individual project which exceeds $250,000; and

- 2031: Three projects totaling $250,000, with no individual project which exceeds $150,000.

The number of individual major maintenance projects for Campbell Unit 1 is as follows:

- 2027: Seven projects totaling $2,129,667, with no individual project which exceeds $689,667;
- 2028: Six Projects totaling $2,351,167, with no individual project which exceeds $750,000;
- 2029: Six Projects totaling $1,952,667, with no individual project which exceeds $712,667;
- 2030: Four Projects totaling $1,300,000, with no individual project which exceeds $500,000; and
- 2031: Two Projects totaling $300,000, with no individual project which exceeds $200,000.

The number of individual major maintenance projects for Campbell Unit 2 is as follows:

- 2027: Seven projects totaling $1,423,333, with no individual project which exceeds $500,000;
- 2028: Six Projects totaling $1,533,833, with no individual project which exceeds $500,000;
- 2029: Six Projects totaling $3,294,333, which includes;
  - Campbell 2 Turbine Valve Inspection ($1,400,000); and
  - Five Projects totaling $1,894,333 with no individual project which exceeds $500,000;
- 2030: Four Projects totaling $1,204,833, with no individual project which exceeds $404,833; and
- 2031: Two Projects totaling $300,000, with no individual project which exceeds $200,000.

The number of individual major maintenance projects for Campbell Unit 3 is as follows:

- 2027: Nine projects totaling $2,560,600, with no individual project which exceeds $500,000;

- 2028: Six Projects totaling $1,830,600, with no individual project which exceeds $500,000;
- 2029: Eight Projects totaling $3,860,600, which includes:
    - Campbell 3 Turbine Valve Inspection ($1,300,000);
    - Campbell 3 Base Outage Boiler and Critical Maintenance ($1,100,000); and
    - Six Projects totaling $1,460,600 with no individual project which exceeds $500,000;
- 2030: Six Projects totaling $1,910,600, with no individual project which exceeds $500,000;
- 2031: Seven Projects totaling $1,960,600, with no individual project which exceeds $500,000;
- 2032: Seven Projects totaling $15,330,600, which includes:
    - Campbell 3 Turbine Overhaul ($12,000,000);
    - Campbell 3 Base Outage Boiler and Critical Maintenance ($2,000,000); and
    - Five Projects totaling $1,330,600 with no individual project which exceeds $500,000;
- 2033: Eight Projects totaling $3,860,600, which includes:
    - Campbell 3 Turbine Valve Inspection ($1,300,000);
    - Campbell 3 Base Outage Boiler and Critical Maintenance ($1,100,000); and
    - Six Projects totaling $1,460,600 with no individual project which exceeds $500,000;
- 2034: Five Projects totaling $1,710,600, with no individual project which exceeds $500,000;
- 2035: Eight Projects totaling $2,260,600, with no individual project which exceeds $500,000;
- 2036: Six Projects totaling $1,850,600, with no individual project which exceeds $500,000;

- 2037: Eight Projects totaling $3,960,600, which includes:
  - Campbell 3 Turbine Valve Inspection ($1,400,000);
  - Campbell 3 Base Outage Boiler and Critical Maintenance ($1,100,000); and
  - Six Projects totaling $1,460,600 with no individual project which exceeds $500,000;
- 2038: Five Projects totaling $1,360,600, with no individual project which exceeds $500,000; and
- 2039: Three Projects totaling $310,600, with no individual project which exceeds $110,600.

Q. Please explain Exhibit A-52 (NJK-3), page 2.

A. Exhibit A-52 (NJK-3), page 2, shows the Company's projected major maintenance expenses for Karn Units 3 and 4 for the cases in which Karn Units 3 and 4 retire on May 31, 2023 or May 31, 2025. The projected major maintenance expenses are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-52 (NJK-3), page 2, also shows the difference in major maintenance expenses for each calendar year relative to the base case. Exhibit A-52 (NJK-3), page 2, line 13, column (c), shows that the Company would avoid $10,050,000 in major maintenance expenses if Karn Units 3 and 4 are retired on May 31, 2023. Exhibit A-52 (NJK-3), page 2, line 13, column (f), shows that the Company would avoid $5,700,000 in major maintenance expenses if Karn Units 3 and 4 are retired on May 31, 2025.

Q. Please explain Exhibit A-52 (NJK-3), page 3.

A. Exhibit A-52 (NJK-3), page 3, shows the Company's projected major maintenance expenses for Campbell Unit 3 for the cases in which Campbell Unit 3 retires on May 31, 2025, or on May 31, 2032. The projected major maintenance expenses are shown for each calendar year from January 1, 2020 through May 31, 2039. Exhibit A-52 (NJK-3), page 3, also shows the difference in major maintenance expenses for each calendar year relative to the base case. Exhibit A-52 (NJK-3), page 3, line 21, column (c), shows that the Company would avoid $57,555,000 in major maintenance expenses if Campbell Unit 3 is retired on May 31, 2025. Exhibit A-52 (NJK-3), page 3, line 21, column (f), shows that the Company would avoid $29,984,000 in major maintenance expenses if Campbell Unit 3 is retired on May 31, 2032. Campbell Units 1 and 2 are not reflected in Exhibit A-52 (NJK-3), page 3, because the Campbell Unit 3 early retirement case assumes that Campbell Units 1 and 2 retire in a similar timeframe and, therefore, have identical costs to those in the base case through 2026 and 2032.

Q. Please explain Exhibit A-52 (NJK-3), page 4.

A. Exhibit A-52 (NJK-3), page 4, shows the Company's projected major maintenance expenses for Campbell Units 1 and 2 for the cases in which Campbell Unit 1 retires on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected major maintenance expenses are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-52 (NJK-3), page 4, also shows the difference in major maintenance expenses for each calendar year relative to the base case. Exhibit A-52 (NJK-3), page 4, line 13, columns (d) and (e), show that the Company would avoid $14,516,000 in major maintenance expenses at Campbell Unit 1 and incur no incremental major maintenance expenses at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2024. Exhibit A-52 (NJK-3), page 4, line 13, columns (i) and (j), shows that the Company would avoid $12,114,000 in major maintenance expenses at Campbell Unit 1 and incur no incremental major maintenance expenses at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2025. Exhibit A-52 (NJK-3), page 4, line 26, columns (d) and (e), shows that the Company would avoid $10,696,000 in major maintenance expenses at Campbell Unit 1 and incur no incremental major maintenance expenses at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2026. Exhibit A-52 (NJK-3), page 4, line 26, columns (i) and (j), shows that the Company would avoid $6,100,000 in major maintenance expenses at Campbell Unit 1 and incur no incremental major maintenance expenses at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-52 (NJK-3), page 4, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 major maintenance expenses as it is assumed that unit separation major maintenance expenses reflected in the base case are not avoided.

Q. Please explain Exhibit A-52 (NJK-3), page 5.

A. Exhibit A-52 (NJK-3), page 5, shows the Company's projected major maintenance expenses for Campbell Units 1 and 2 for the cases in which Campbell Unit 2 retires on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected major maintenance expenses are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-52 (NJK-3), page 5, also shows the difference in major maintenance expenses for each calendar year relative to the base case. Exhibit A-52 (NJK-3), page 5, line 13, columns (d) and (e), shows that the Company would avoid $14,625,000 in major maintenance expenses at Campbell Unit 2 and incur no incremental major maintenance expenses at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2024. Exhibit A-52 (NJK-3), page 5, line 13, columns (i) and (j), shows that the Company would avoid $13,385,000 in major maintenance expenses at Campbell Unit 2 and incur no incremental major maintenance expenses at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2025. Exhibit A-52 (NJK-3), page 5, line 26, columns (d) and (e), shows that the Company would avoid $12,185,000 in major maintenance expenses at Campbell Unit 2 and incur no incremental major maintenance expenses at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2026. Exhibit A-52 (NJK-3), page 5, line 26, columns (i) and (j), show that the Company would avoid $6,427,000 in major maintenance expenses at Campbell Unit 2 and incur no incremental major maintenance expenses at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-52 (NJK-3), page 5, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 major maintenance expenses as it is assumed that unit separation major maintenance expenses reflected in the base case are not avoided.

Q. Please explain Exhibit A-52 (NJK-3), page 6.

A. Exhibit A-52 (NJK-3), page 6, shows the Company's projected major maintenance expenses for Campbell Units 1 and 2 for the cases in which both Campbell Units 1 and 2 retire on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected major maintenance expenses are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-52 (NJK-3), page 6, also shows the difference in major maintenance expenses for each calendar year relative to the base case. Exhibit A-52 (NJK-3), page 6, line 13, columns (d) and (e), shows that the Company would avoid $14,516,000 in major maintenance expenses at Campbell Unit 1 and $14,625,000 in major maintenance expenses at Campbell Unit 2 if both units are retired on May 31, 2024. Exhibit A-52 (NJK-3), page 6, line 13, columns (i) and (j), shows that the Company would avoid $12,114,000 in major maintenance expenses at Campbell Unit 1 and $13,385,000 in major maintenance expenses at Campbell Unit 2 if both units are retired on May 31, 2025. Exhibit A-52 (NJK-3), page 6, line 26, columns (d) and (j), shows that the Company would avoid

$10,696,000 in major maintenance expenses at Campbell Unit 1 and $12,185,000 in major maintenance expenses at Campbell Unit 2 if both units are retired on May 31, 2026. Exhibit A-52 (NJK-3), page 6, line 26, columns (i) and (j), shows that the Company would avoid $6,100,000 in major maintenance expenses at Campbell Unit 1 and $6,427,000 in major maintenance expenses at Campbell Unit 2 if both units are retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-52 (NJK-3), page 6, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 major maintenance expenses because the unit separation major maintenance expenses reflected in the base case are not avoided.

Q. Please explain Exhibit A-53 (NJK-4), page 1.

A. Exhibit A-53 (NJK-4), page 1, shows the Company's projected base O&M expenses at the Karn and Campbell sites for each calendar year over the period from January 1, 2020 through May 31, 2039 in the base case. In this case, Karn Units 1 and 2 retire May 31, 2023, Karn Units 3 and 4 and Campbell Units 1 and 2 retire May 31, 2031, and Campbell Unit 3 retires May 31, 2039.

Q. Please explain Exhibit A-53 (NJK-4), page 2.

A. Exhibit A-53 (NJK-4), page 2, shows the Company's projected base O&M expenses for Karn Units 3 and 4 for the cases in which Karn Units 3 and 4 retire on May 31, 2023 or May 31, 2025. The projected expenses are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-53 (NJK-4), page 2, also shows the difference in expenses for each calendar year relative to the base case. Exhibit A-53 (NJK-4), page 2, column (c), shows that the Company would avoid $92,202,000 in base O&M expenses if Karn Units 3 and 4 retire on May 31, 2023. Exhibit A-53 (NJK-4), page 2, column (f), shows that the Company would avoid $73,220,000 in base O&M expenses if Karn Units 3 and 4 retire on May 31, 2025.

Q. Please explain Exhibit A-53 (NJK-4), page 3.

A. Exhibit A-53 (NJK-4), page 3, shows the Company's projected base O&M expenses for the Campbell Unit 3 for the cases in which Campbell Unit 3 retires on May 31, 2025, or on May 31, 2032. The projected expenses are shown for each calendar year from January 1, 2020 through May 31, 2039. Exhibit A-53 (NJK-4), page 3, also shows the difference in expenses for each calendar year relative to the base case. Exhibit A-53 (NJK-4), page 3, column (c) shows that the Company would avoid $432,791,000 in base O&M expenses if Campbell Unit 3 retires on May 31, 2025 and Exhibit A-53 (NJK-4), page 3, column (f), shows that the Company would avoid $232,813,000 in base O&M expenses if Campbell Unit 3 retires on May 31, 2032.

Q. Please explain Exhibit A-53 (NJK-4), pages 4 and 5.

A. Exhibit A-53 (NJK-4), pages 4 and 5, shows the Company's projected base O&M expenses for Campbell Units 1 and 2 for the cases in which Campbell Unit 1 retires on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected base O&M expenses are shown for each calendar year from January 1, 2020 through May 31, 2039. Exhibit A-53 (NJK-4), pages 4 and 5, also shows the difference in major maintenance expenses for each calendar year relative to the base case. Exhibit A-53 (NJK-4), page 4, line 21, columns (d), (e), and (f) shows that the Company would avoid $71,086,000 in base O&M expenses at Campbell Unit 1 and incur incremental base O&M expenses of $9,334,000 at Campbell Unit 2 and incremental base O&M expenses of $28,524,000 at Campbell Unit 3 if Campbell Unit 1 is retired on May 31, 2024. Exhibit A-53 (NJK-4), page 4, line 21, columns (j), (k), and (l), shows that the Company would avoid $61,524,000 in base O&M expenses at Campbell Unit 1 and incur incremental base O&M expenses of $8,172,000 at Campbell Unit 2 and incremental base O&M expenses of $26,953,000 at Campbell Unit 3 if Campbell Unit 1 is retired on May 31, 2025. Exhibit A-53 (NJK-4), page 5, line 21, columns (d), (e), and (f), shows that the Company would avoid $51,771,000 in base O&M expenses at Campbell Unit 1 and incur incremental base O&M expenses of $6,983,000 at Campbell Unit 2 and incremental base O&M expenses of $25,313,000 at Campbell Unit 3 if Campbell Unit 1 is retired on May 31, 2026. Exhibit A-53 (NJK-4), page 5, line 21, columns (j), (k), and (l), shows that the Company would avoid $31,675,000 in base O&M expenses at Campbell Unit 1 and incur incremental base O&M expenses of $4,531,000 at Campbell Unit 2 and incremental base O&M expenses of $21,990,000 at Campbell Unit 3 if Campbell Unit 1 is retired on May 31, 2028.

Q. Please explain Exhibit A-53 (NJK-4), pages 6 and 7.

A. Exhibit A-53 (NJK-4), pages 6 and 7, shows the Company's projected base O&M expenses for Campbell Units 1 and 2 for the cases in which Campbell Unit 2 retires on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected base O&M expenses are shown for each calendar year from January 1, 2020 through May 31, 2039. Exhibit A-53 (NJK-4), pages 6 and 7, also shows the difference in major maintenance expenses for each calendar year relative to the base case. Exhibit A-53 (NJK-4), page 6, line 21, columns (d), (e), and (f), shows that the Company would avoid $137,616,000 in base O&M expenses at Campbell Unit 2 and incur incremental base O&M expenses of $9,857,000 at Campbell Unit 1 and incremental base O&M expenses of $38,029,000 at Campbell Unit 3 if Campbell Unit 2 is retired on May 31, 2024. Exhibit A-53 (NJK-4), page 6, line 21, columns (j), (k), and (l) show that the Company would avoid $136,376,000 in base O&M expenses at Campbell Unit 2 and incur incremental base O&M expenses of $8,626,000 at Campbell Unit 1 and incremental base O&M expenses of $35,919,000 at Campbell Unit 3 if Campbell Unit 2 is retired on May 31, 2025. Exhibit A-53 (NJK-4), page 7, line 21, columns (d), (e), and (f) show that the Company would avoid $135,176,000 in base O&M expenses at Campbell Unit 2 and incur incremental base O&M expenses of $7,374,000 at Campbell Unit 1 and incremental base O&M expenses of $33,759,000 at Campbell Unit 3 if Campbell Unit 2 is retired on May 31, 2026. Exhibit A-53 (NJK-4), page 7, line 21, columns (j), (k), and (l), shows that the Company would avoid $129,417,000 in base O&M expenses at Campbell Unit 2 and incur incremental base O&M expenses of $4,785,000 at Campbell Unit 1 and incremental base O&M expenses of $29,319,000 at Campbell Unit 3 if Campbell Unit 2 is retired on May 31, 2028.

Q. Please explain Exhibit A-53 (NJK-4), pages 8 and 9.

A. Exhibit A-53 (NJK-4), pages 8 and 9, shows the Company's projected base O&M expenses for Campbell Units 1 and 2 for the cases in which both Campbell Units 1 and 2 retire on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected base O&M expenses are shown for each calendar year from January 1, 2020 through May 31, 2039. Exhibit A-53 (NJK-4), pages 8 and 9, also shows the difference in major maintenance expenses for each calendar year relative to the base case. Exhibit A-53 (NJK-4), page 8, line 21, columns (d), (e), and (f), shows that the Company would avoid $71,086,000 in base O&M expenses at Campbell Unit 1, $97,270,000 in base O&M expenses at Campbell Unit 2 and incur incremental base O&M expenses of $9,497,000 at Campbell Unit 3 if Campbell Units 1 and 2 are retired on May 31, 2024. Exhibit A-53

(NJK-4), page 8, line 21, columns (j), (k), and (l), shows that the Company would avoid $61,524,000 in base O&M expenses at Campbell Unit 1, $84,186,000 in base O&M expenses at Campbell Unit 2 and incur incremental base O&M expenses of $8,989,000 at Campbell Unit 3 if Campbell Units 1 and 2 are retired on May 31, 2025. Exhibit A-53 (NJK-4), page 9, line 21, columns (d), (e), and (f), shows that the Company would avoid $51,771,000 in base O&M expenses at Campbell Unit 1, $70,840,000 in base O&M expenses at Campbell Unit 2 and incur incremental base O&M expenses of $8,439,000 at Campbell Unit 3 if Campbell Units 1 and 2 are retired on May 31, 2026. Exhibit A-53 (NJK-4), page 9, line 21, columns (j), (k), and (l), shows that the Company would avoid $31,675,000 in base O&M expenses at Campbell Unit 1, $43,343,000 in base O&M expenses at Campbell Unit 2 and incur incremental base O&M expenses of $7,331,000 at Campbell Unit 3 if Campbell Units 1 and 2 are retired on May 31, 2028.

Q. Please explain Exhibit A-54 (NJK-5).

A. Exhibit A-54 (NJK-5) shows the projected capital expenditures and costs of removal for the Company's remaining generation units. Lines 1 through 5 reflect the total for each year of capital expenditures and costs of removal. Lines 6 through 10 reflect the total for each year of capital expenditures only.

Q. Did the Company account for the capital expenditures shown in Exhibit A-54 (NJK-5) in its IRP modeling?

A. No. The Company's IRP modeling assumed that the generation units listed in Exhibit A-54 (NJK-5) would continue operating until reaching the end of their lifespan when their book values are fully depreciated.

SECTION III: PROJECTED CAPITAL EXPENDITURES AND O&M EXPENSES OF NEW GAS PLANTS

Q. Please explain Exhibit A-55 (NJK-6).

A. Exhibit A-55 (NJK-6) shows the projected capital expenditures and major maintenance expenses for the new gas plants for the period of January 1, 2020 through May 31, 2040. These are the costs and the date range that the Company used for modeling purposes in this IRP.

Q. Please explain Exhibit A-55 (NJK-6), page 1.

A. Exhibit A-55 (NJK-6), page 1, shows the Company's projected capital expenditures associated with the General Electric Long Term Service Agreement ("LTSA") for DIG and the Mitsubishi LTSA for Covert, for the period from January 1, 2020 through May 31, 2040. As discussed by Company witness Richard T. Blumenstock, the Company would complete the acquisition of Covert by May 31, 2023 and the acquisition of DIG by May 31, 2025, if the Company's PCA is approved. Exhibit A-55 (NJK-6), page 1, line 22, column (b), shows that the total projected LTSA capital expenditures for Covert through 2040 are $209,026,000, and Exhibit A-55 (NJK-6), page 1, line 22, column (c), shows that the total projected LTSA capital expenditures for DIG are $280,091,000.

Q. Please explain Exhibit A-55 (NJK-6), page 2.

A. Exhibit A-55 (NJK-6), page 2, shows the Company's projected capital expenditures for the new natural gas plants for work that is not covered by the LTSA for Covert and DIG, as well as all projected capital expenditures for Kalamazoo and Livingston, for the period from January 1, 2020 through May 31, 2040. As discussed by Company witness Richard T. Blumenstock, the Company would complete the acquisition of Kalamazoo and Livingston by May 31, 2025, if the Company's PCA is approved. Exhibit A-55 (NJK-6), page 2, line 22, column (b), shows that the total projected non-LTSA capital expenditures for Covert through 2040 are $114,887,000, and Exhibit A-55 (NJK-6), page 2, line 22, column (c), shows that the total projected non-LTSA capital expenditures for DIG, Kalamazoo and Livingston are $151,696,000. The projected spike in capital expenditures for non-LTSA capital expenditures in 2027 reflects work to perform rotor replacement at Covert.

Q. Please explain Exhibit A-55 (NJK-6), page 3.

A. Exhibit A-55 (NJK-6), page 1, shows the Company's projected major maintenance expenses for the new natural gas plants associated with the General Electric and Mitsubishi LTSAs for Covert and DIG for the period from January 1, 2020 through May 31, 2040. Exhibit A-55 (NJK-6), page 3, line 22, column (b), shows that the total projected LTSA major maintenance expenses for Covert through 2040 are $69,829,000, and Exhibit A-55 (NJK-6), page 3, line 22, column (c), shows that the total projected LTSA major maintenance expenses for DIG are $50,694,000.

Q. Please explain Exhibit A-55 (NJK-6), page 4.

A. Exhibit A-55 (NJK-6), page 4, shows the Company's projected base O&M expenses for the new natural gas plants for work that is not covered by the LTSA for Covert and DIG, as well as the base O&M expenses for Kalamazoo and Livingston, for the period from January 1, 2020 through May 31, 2040. Exhibit A-55 (NJK-6), page 4, line 22, column (b), shows that the total projected non-LTSA base O&M expenses for Covert through 2040 are $511,184,000, and Exhibit A-55 (NJK-6), page 4, line 22, column (c), shows that the total projected non-LTSA base O&M expenses for DIG, Kalamazoo, and Livingston are

$543,256,000. The non-LTSA base O&M expenses include both fixed and variable O&M expenses.

SECTION IV: SEPARATION ACTIVITY COSTS

Q. Please explain Exhibit A-56 (NJK-7).

A. Exhibit A-56 (NJK-7) shows the separation activity costs that the Company would incur in each retirement case. Exhibit A-56 (NJK-7), lines 1 through 9, shows the separation activity costs as they were modeled by the Company for this IRP, based on assumptions made at the time that the modeling was conducted.

Q. What are separation activity costs?

A. Separation activity costs cover those activities that are required to keep the remaining units at a site functioning when other units are retired.

Q. Are there any separation activity costs in the base case?

A. Yes. Exhibit A-56 (NJK-7), lines 1 and 2, shows that unit separation costs were modeled in the base case.

Q. What separation activity costs did the Company model in the event that Karn Units 3 and 4 were retired in 2023?

A. As shown in Exhibit A-56 (NJK-7), line 3, if Karn Units 3 and 4 are retired in 2023, the Company's IRP modeling assumes a reduction in the separation activity costs at Karn Unit 3 and 4 from $28,651,000 to $13,186,000. These costs could potentially be avoided in 2022 and 2023 once a decision to retire Karn Units 3 and 4 in 2023 is finalized.

Q. What separation activity costs did the Company model in the event that Campbell Unit 3 operated through May 31, 2039?

A. As shown in Exhibit A-56 (NJK-7), line 2, if Campbell Unit 3 operates through May 31, 2039, the Company projects that it will incur unit separation costs of $64,146,000. However, as reflected on lines 7 and 9, a Campbell Unit 3 retirement in 2025 or 2032, if coupled with a Campbell Unit 1 and 2 retirement, would allow the Company to entirely avoid the unit separation costs.

Q. What separation activity cost does the Company expect to actually incur in the event that Campbell Units 1 and 2 are retired early?

A. As shown in Exhibit A-56 (NJK-7), lines 4, 5, 6, and 8, the Company is still projecting that it would incur $64,146,000 in separation activity costs at Campbell Unit 3 in the 2024, 2025, 2026, and 2028 Campbell Unit 1 and 2 retirement cases.

Q. Is the Company requesting Commission approval of the separation activity costs for the Campbell site in this IRP proceeding?

A. No, the Company is not making such a request in *this* proceeding. The Company developed its projections of $64,146,000 in separation activity costs based on an external conceptual engineering study of the Campbell Unit 1 and 2 unit separation costs. The Company's base case assumed that this separation work would begin in 2028 in anticipation of a May 31, 2031 retirement date for Campbell Units 1 and 2. The Company believes this estimate is accurate and, as noted above, used this figure when conducting its IRP modeling. To the extent necessary, the Company will develop a more detailed engineering study and construction plans for the separation activity. Those more specific projections for separation activity spending will be presented to the Commission and requested for approval in a future regulatory proceeding.

Q. What unit separation activity work would be required at the Campbell site?

A. The following is a high level list of activities that would be performed as part of the Campbell site unit separation:

- Mechanical isolation, cut, & caps, and new electric heating;
- Unit 1 & 2 basement sump modifications and tunnel dewatering;
- Coal pile runoff discharge treatment;
- Unit 1 & 2 communications fed from the Unit 2 switchgear building;
- Unit 2 switchgear building repower - fuel handling and Unit 1 & 2;
- Stackout and reclaim system modifications; and
- Fuel Handling Conveyor reroute/rebuild.

Q. What separation activity work does the Company plan to avoid if Karn Units 3 and 4 are retired early?

A. Under a Karn Unit 3 and 4 early retirement case, the Company would avoid capital expenditures in 2022 and 2023. It is impractical to realistically avoid any capital costs in 2021 due to the projected timing of an order in this proceeding.

Q. What is the Company's schedule for completing this work?

A. This separation work is currently underway in order to successfully retire Karn Units 1 and 2 on May 31, 2023.

Q. What are the implications of retiring Karn Units 3 and 4 in 2023 on the unit separation timeline?

A. Exhibit A-56 (NJK-7), line 3, reflects an extremely aggressive reduction in unit separation capital expenditures for this retirement case in 2022. Due to the potential timing of a final order approving the Company's PCA, it is unrealistic to avoid any unit separation capital expenditures in 2021, and the level of capital expenditures that the Company can avoid in 2022 is entirely dependent on when it receives a decision on its PCA. In order to achieve retirement of Karn Units 1 and 2 on May 31, 2023, the Company must continue to proceed with its current separation of these units from Karn Units 3 and 4.

Q. What separation activity costs did the Company model in the event that Campbell Units 1 and 2 were retired in 2024, 2025, 2028 or 2031?

A. Exhibit A-56 (NJK-7), lines 4, 5, 6, and 8, shows the costs that the Company's IRP modeling assumes would be incurred at Campbell Unit 3 if both Campbell Units 1 and 2 were retired in 2024, 2025, 2026, 2028. If only one of the two units is retired, the separation activity costs would not be incurred at Campbell Unit 3 until 2028 as modeled in the base case assuming that Campbell Unit 3 operates through 2039. However, if Campbell Unit 3 is retired in 2025 or 2032, and its retirement is coupled with a Campbell Unit 1 and 2 retirement, the unit separation costs can be avoided. The separation activity costs at Campbell Unit 3 in these bases would be an estimated $64,146,000, incurred from 2028 through 2031, to prepare Campbell Unit 3 to operate on a standalone basis once Campbell Units 1 and 2 are retired.

Q. What separation activity costs would the Company expect to actually incur in the event that Campbell Units 1 and 2 are retired early?

A. As shown in Exhibit A-56 (NJK-7), lines 4, 5, 6, and 8, the Company is still projecting that it would incur an estimated $64,146,000 in separation activity costs at Campbell Unit 3 that were projected in the IRP modeling. As previously discussed, these costs can be avoided with an early Campbell Unit 3 retirement case.

Q. If Campbell Units 1 and 2 were retired, what separation activity work would the Company plan to complete?

A. In order to allow Campbell Unit 3 to remain operating after the retirement of Campbell Units 1 and 2, the Company would leave the structure housing Campbell Units 1 and 2 in place, with its tripper deck remaining in service. All fuel handling equipment would have to be rerouted and fuel handling, the tripper deck, and ventilation and heating equipment at the site would have to be repowered from Campbell Unit 3. The fuel handling conveyor reroute work constitutes a large portion of the costs reflected in Exhibit A-56 (NJK-7), lines 4, 5, 6, and 8. Using this approach would involve fewer upfront costs and would be logistically simpler than building new fuel handling equipment. Leaving the structure housing Campbell Units 1 and 2 standing would require the Company to incur some incremental major maintenance expenses, as discussed later in my direct testimony. Because the structure would remain standing, Campbell Units 1 and 2 would not formally enter the cold and dark period, and it would likely be difficult to pursue any redevelopment opportunities at the site.

SECTION V: UNAVOIDABLE, AVOIDABLE, AND INCREMENTAL COSTS

Q. Please explain Exhibit A-57 (NJK-8).

A. Exhibit A-57 (NJK-8) illustrates the Company's unavoidable, avoidable, and incremental capital expenditures for each of the early retirement cases.

Q. What are unavoidable capital expenditures?

A. Unavoidable capital expenditures represent capital expenditures that the Company must make even in the event that one or more of the various retirement cases for Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3 are retired in 2023, 2024, 2025, 2026, 2028, or 2032.

Q. Please provide an example of an unavoidable capital expenditure.

A. The Company's overall plans for capital expenditures were discussed above; the unavoidable capital expenditures are those that the Company must make in any case to ensure safety and reliability. One example of an unavoidable capital expenditure is the Campbell Unit 1 PJFF bag replacement. PJFF bags are part of the AQCS equipment which was installed to comply with Environmental Protection Agency requirements. These PJFF bags remove dry fly ash from the gas exiting the boiler and need to be replaced every four or five years to avoid failure due to plugging. Maintaining the integrity of the bags and being able to properly operate the bag cleaning system are necessary for plant operation within regulatory limits. Multiple bag failures could cause the unit to exceed opacity, resulting in unit derate or forced outage based upon the consent decree. Performance of this work will provide continued environmental compliance. This work is generally performed on a seven-year cycle, is due to be completed in 2023, and would be required to be completed in the 2025 through 2028 Campbell Unit 1 retirement cases.

Q. What are avoidable capital expenditures?

A. Avoidable capital expenditures represent capital expenditures that are currently scheduled to be made at Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3, but that the Company would forego making in the event that one or more of the various retirement cases for Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3 in 2023, 2024, 2025, 2026, 2028, or 2032 are made. The avoidable capital expenditures were discussed above in my discussion of Exhibit A-51 (NJK-2).

Q. What are incremental costs?

A. Incremental capital expenditures represent capital expenditures at Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3 that are not currently included in the Company's base plans, but that the Company would need to add in the event that one or more of the various retirement cases for Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3 in 2023, 2024, 2025, 2026, 2028, or 2032 are made.

Q. Please explain the incremental capital expenditures shown in Exhibit A-57 (NJK-8).

A. The incremental capital expenditures for each retirement case include the expenditures at Campbell Unit 1 in the cases in which Campbell Unit 2 is retired, and incremental capital expenditures at Campbell Unit 2 in the cases in which Campbell Unit 1 is retired. These costs are reflected in Exhibit A-57 (NJK-8), page 2, lines 4 and 8, for the 2024 retirement case. In Exhibit A-51 (NJK-2): (i) page 4, line 13, column (e), shows that if Campbell Unit 1 is retired in 2024, the Company will have $253,000 in incremental capital expenditures at Campbell Unit 2; and (ii) page 5, line 13, column (d), shows that if Campbell Unit 2 is retired in 2024, the Company will have $322,000 in incremental capital expenditures at Campbell Unit 1. These costs represent shifting of fuel handling and infrastructure from the retired unit to the remaining unit for each of these two cases.

Q. Please explain Exhibit A-58 (NJK-9).

A. Exhibit A-58 (NJK-9) illustrates the Company's unavoidable, avoidable, and incremental major maintenance expenses for each of the early retirement cases.

Q. What are unavoidable expenses?

A. Unavoidable expenses represent major maintenance expenses that the Company must incur even in the event that one or more of the various retirement cases for Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3 are retired in 2023, 2024, 2025, 2026, 2028, or 2032.

Q. Please provide an example of an unavoidable expense.

A. Consumers Energy's overall plans for expenses were discussed above; the unavoidable expenses are those that the Company must incur in any case to ensure safety and reliability. As an example, if Campbell Units 1, 2, or 3 are selected for any of the early retirement cases in in 2024, 2025, 2026, 2028, or 2032, the Company will still have O&M expenses for Mill major maintenance.

Q. What are avoidable major maintenance expenses?

A. Avoidable expenses represent major maintenance expenses that are currently scheduled to be made at Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3, but that the Company would forego in the event that one or more of the various retirement cases for Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3 in 2023, 2024, 2025, 2026, 2028, or 2032 are made. The avoidable expenses were discussed above in my discussion of Exhibit A-52 (NJK-3).

Q. What are incremental major maintenance expenses?

A. Incremental major maintenance expenses represent O&M expenses at Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3 that are not currently included in Consumers Energy's base plans, but that the Company would need to add in the event that one or more of the various retirement cases for Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3 in 2023, 2024, 2025, 2026, 2028, or 2032 are made. As shown in Exhibit A-58 (NJK-9), pages 1 through 6, the Company has not projected any incremental major maintenance expenses for any of the retirement cases.

SECTION VI: PERFORMANCE OF EXISTING GENERATION FLEET

Q. Please explain Exhibit A-59 (NJK-10), page 1.

A. Exhibit A-59 (NJK-10), page 1, illustrates the historic and projected performance of the Company's coal-fired generating units at the Campbell and Karn sites, measuring their Random Outage Rate ("ROR").

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 improves 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. Initial ROR projections are based on five-year historic averages and then adjusted to reflect current operating conditions and projected unit investment. Further than five years into the future, it is increasingly difficult to accurately project ROR, as the number of unknown external factors increase. Therefore, the projected RORs for 2026 through 2031 are based on an assumed slight decrease in performance, accounting for standard corrective capital investments and maintenance.

Q. Does the ROR measurement reflect customer value?

A. While a reduced ROR may result in a benefit to customers because of the increased availability of the unit or category of unit, ROR is not itself a measure of customer benefit. The Company utilizes Net Energy Value ("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. The historical values are presented in table below.

TABLE 2

	2016	2017	2018	2019	2020	TOTAL
CAMPBELL 1	$5,963,929.	$4,201,021.	$8,497,680.	$5,687,739.	$1,468,569.	$25,818,937.
CAMPBELL 2	$6,192,416.	$2,219,726.	$9,133,940.	$4,809,091.	$948,961.	$23,304,133.
CAMPBELL 3	$19,778,737.	$28,200,856.	$47,291,421.	$30,225,507.	$19,665,066.	$145,161,587.
KARN 1	$5,989,670.	$8,176,719.	$7,238,867.	$1,954,120.	$1,362,009.	$24,721,385.
KARN 2	$5,981,023.	$4,466,650.	$6,489,054.	$438,945.	$438,017.	$17,813,688.

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. What are the Company's expectations regarding ROR and NEV for its coal-fired generating units?

A. As presented on Exhibit A-59 (NJK-10), page 1, the Company has projected a steady decline in ROR through retirement for Campbell Units 1 and 2 and Karn Units 1 and 2. As previously discussed, the Company's projections of ROR take into account the projected unit investment and, given the current retirement dates for these units, investments targeted at improving ROR are generally uneconomic and not likely to result in providing incremental customer value. As a result, it is likely that the NEV for these units will also decline slightly as they move closer to retirement.

Q. Please explain Exhibit A-59 (NJK-10), page 2.

A. Exhibit A-59 (NJK-10), page 2, illustrates the historic Equivalent Forced Outage Rate Demand ("$EFOR_d$") of the Company's generation units at the Campbell and Karn sites.

Q. Please define EFOR$_d$.

A. EFOR$_d$ represents the hours of unit failure (Forced Outage Hours demand + Equivalent Forced Derate Hours demand), given as a percentage of the total hours of unit availability (Service Hours + Forced Outage Hours demand + Equivalent Forced Derate Hours During Reserve Shutdown).

Q. What does the ROR and EFOR$_d$ information in Exhibit A-59 (NJK-10) indicate about the condition of the existing equipment at Campbell Units 1 and 2 and Karn Units 1 and 2?

A. Exhibit A-59 (NJK-10) indicates that Campbell Units 1 and 2 have generally performed more reliably than Karn Units 1 and 2 as measured by ROR and EFOR$_d$, and the ROR of Campbell Units 1 and 2 are projected to continue demonstrating better reliability than Karn Units 1 and 2 in future years leading up to retirement. This indicates that the condition of existing equipment at Campbell Units 1 and 2 is generally better than that at Karn Units 1 and 2.

Q. Are there other measures used to inform operational and financial decisions in order to optimize the customer value of the generating unit?

A. Investments made to improve reliable operations at generating units can provide capacity value as well as energy value. The Company is required by the Midcontinent Independent System Operation, Inc. ("MISO") to secure enough capacity on an annual basis to cover all of its load, plus a reserve margin. All of the Company's units provide some capacity towards meeting this obligation and EFOR$_d$ is a measure which factors into the determination of that capacity.

Q. Please explain Confidential Exhibit A-60 (NJK-11), page 1.

A. Confidential Exhibit A-60 (NJK-11), page 1, illustrates the projected heat rates for Campbell Units 1 and 2 in the base case and the various retirement cases.

Q. Please define heat rate.

A. The heat rate or efficiency of a unit is the amount of energy used by an electrical generator to produce one kilowatt-hour (kWh) of electricity, represented in BTU/kWh.

Q. How have the changes in projected investment in the various retirement cases for Campbell Unit 1 impacted its projected heat rates?

A. As reflected on Confidential Exhibit A-60 (NJK-11), lines 1-12, the heat rate for Campbell Unit 1 through 2023 is identical in the base case and each retirement case. However, in the 2024, 2025, and 2026 Campbell Unit 1 retirement cases, the heat rate degrades (increases) in 2024 due to the elimination of the project to replace the air preheater baskets and seals in 2023 and 2024. As such, only the base case and 2028 retirement case reflect a heat rate improvement in 2024 and beyond. No other projects in the base case provide heat rate improvement.

Q. How have the changes in projected investment in the various retirement cases for Campbell Unit 2 impacted its projected heat rates?

A. As reflected on Confidential Exhibit A-60 (NJK-11), lines 13-24, the heat rate for Campbell Unit 2 through 2031 is identical in the base case and each retirement case. The reason for this is that there are no major Campbell Unit 2 projects with heat rate effects after the Turbine/Generator work and air heater seal replacement work in 2021. As such, the heat rate degradation is the same for all cases.

SECTION VII: EXECUTION RISKS OF EARLY RETIREMENT

Q. What execution risks does the Company face in its plan to retire the Campbell site in 2025?

A. Since the Company is recommending that the Campbell site be retired early, there are several factors that could make the actual operation of those units until May 31, 2025 difficult. These factors include issues related to plant maintenance and employee retention.

Q. What are the risks related to plant maintenance?

A. The Company will continue to make capital investments and incur O&M expenses at Campbell site in order to ensure safe operation. However, as the units get closer to their early retirement date, the Company will have to evaluate any unexpected maintenance issues that may arise to determine if the economics of the situation would justify performing repairs. For example, if one of the units experiences a turbine failure one year prior to the retirement date, the Company would consider both the costs and benefits of replacement and/or repair before proceeding. If replacement and/or repair would result in high costs that could not be recovered before retirement, and replacement energy could be purchased through the MISO market, and replacement capacity could be purchased bilaterally, at a more economic price than the price of replacement and/or repair, then the Company could elect to leave the affected unit in an outage until the retirement date.

Q. What are the risks related to employee retention?

A. The Company will develop a thorough plan to ensure that the necessary qualified employees are retained to operate the units through the retirement date, as well as during the cold and dark time period following retirement, as discussed later in my direct testimony. However, once it is certain that the units will retire, employees may begin to seek positions elsewhere in the Company, or externally. In that circumstance, it could become difficult for the units to be safely operated through the retirement date. When the Company retired the Classic 7 in 2016, and made plans to retire Karn Units 1 and 2 in 2023, the Company was able to mitigate these employee retention risks because it had time to develop a transition plan that gave employees needed confidence to remain at those units through the closure date, knowing that they would likely be able to move to other positions within the Company afterward. However, with the retirement of all remaining coal units, the difficulty of this task has significantly increased. Further, the Company has observed situations involving other utilities in which the retirement of a generation plant was made more difficult by less than adequate human resource management and planning. For example, there have been situations at other utilities in which plant employees were not provided any kind of post-closure transition plan, meaning those employees were liable to lose their jobs, resulting in low morale and delays in the retirement of the plant. By having an effective transition plan in place for employees, the Company can effectively mitigate these risks.

Q. Is the Company considering environmental risks in retiring the Campbell site?

A. Yes. When the units are retired, the Company will have to bring the units into compliance with environmental regulations. This will include vacuuming all ash, draining boilers, and removing all oil from the machinery. The Company will ensure that nothing is left at the site that may leak and release pollution into the environment. In performing this environmental work, the Company will ensure that it does not, and will not, exceed any regulatory limits on emissions into local waterways throughout the prolonged cold and dark period, which will require sufficient time during the cold and dark period. If the Company does not have sufficient time to do this cleaning, it runs the risk of significantly increased clean-up costs in order to ensure that the Company does not violate emissions limits and completes all necessary clean-up work. In addition to the clean-up work itself, the Company will also need to address the coal pile. The Company plans to burn the coal pile down in the final weeks of the units' operation, so that as little coal remains onsite as possible. The Company will evaluate remediation of the land on which the coal pile sits to determine if that land can be redeveloped for other purposes.

Q. Is the Company considering risks related to the future use of the site?

A. Yes. The Company has recent experience in evaluating future use of a retired generation unit site, having done so when the Classic 7 were retired and currently doing so for the Karn site. During the Classic 7 retirement process, the Company evaluated various future use options for those sites, and Consumers Energy had enough time in that process to effectively study the divestment of those sites and opportunities to divest to third parties who would also manage facility demolition and redevelopment, mitigating the risk of unnecessarily high costs and optimizing customer value since a specialized firm would manage demolition and redevelopment instead of the Company doing so directly. In the case of Campbell site, the Company would also need time to study different future use options for the site, and to vet different options for both Company-managed demolition and redevelopment and for divestment to a third-party firm to do that work.

Q. Are there future use risks related to the local community?

A. Impacts to the community when the Campbell site retires are discussed later in my direct testimony. At a high level, the retirement will impact the community's tax base and employment base. The Company is committed to assisting in redevelopment of the site to offset these impacts, and to communicating with the community as much as possible to facilitate this.

Q. If Campbell Units 1 and 2 were retired in 2024 instead of 2025, as the Company considered in other cases, would there be additional risks?

A. Yes. As noted above, the Company has demonstrated an ability to responsibly and safely retire and decommission a coal-fired generation unit when given sufficient time to develop a transition plan that ensures needed employee retention so that operations can be appropriately wound down in a safe and environmentally responsible manner, which would also allow the Company to assess impacts to the local community and develop a transition plan for that as well. Assuming that this filing receives Commission approval in 2022, a 2024 retirement date does not give the Company adequate time. A 2024 retirement date would not allow the Company enough time to implement a safe and responsible transition plan for environmental clean-up, for employee transitions, or for community transitions.

Q. Are there any further concerns related to retiring Campbell Units 1 and 2 in 2024 instead of 2025?

A. Yes. The Company has made significant capital investments in Campbell Units 1 and 2 to ensure their compliance with environmental standards as well as to maintain reliability. Operating Campbell Units 1 and 2 until 2025 increases the benefits of those investments as the units will continue to provide energy and capacity for a longer period of time; conversely, retiring Campbell Units 1 and 2 in 2024 would reduce the time that those capital investments provide benefits to customers.

Q. Are there any risks that would result in Campbell site being required to be operated beyond 2025?

A. Yes. To retire a generation unit, the Company must get approval from MISO. MISO will study the Company's retirement proposal to ensure that it does not create transmission reliability concerns, particularly related to maintaining voltage on the transmission system. If MISO finds that transmission reliability concerns will exist, MISO may require one or more of the units to remain in operation until such time that a solution is found and completed to mitigate the reliability problem. As part of its stakeholder process, MISO would consider solutions, such as: (i) re-dispatch or reconfiguration of the transmission system; (ii) special protection schemes; (iii) contracted demand response; (iv) new or expanded generation elsewhere on the system; and (v) transmission expansion.

Q. What would happen if MISO does require one or both units to remain in operation?

A. If MISO makes such a determination, it would designate the unit or units as a System Support Resource ("SSR"). When a unit becomes an SSR, MISO ensures that the unit fully recovers its ongoing operating costs by assigning those costs to affected MISO transmission customers through MISO's Federal Energy Regulatory Commission-regulated transmission rates.

SECTION VIII: TAX, COMMUNITY, AND EMPLOYEE IMPACTS OF EARLY RETIREMENT

Karn Units 3 and 4

Q. What is the tax impact of Karn Units 3 and 4?

A. The Company pays property taxes on Karn Units 3 and 4 that fund local governmental services provided by Hampton Township and Bay County. The units' 2020 taxable value was $25.6 million, which was approximately 0.87% of the total taxable value in Bay

County and 7.6% of the total taxable value in Hampton Township. The units' 2021 taxable value had a small increase of approximately 1%.

Q. Aside from property tax revenues, what other impacts will the retirement of Karn Units 3 and 4 in 2023 have on its respective community?

A. Gas-fired generation units provide employment in the communities in which they are located and can be local economic drivers. Retirement of Karn Units 3 and 4 in combination with Karn Units 1 and 2 will bring economic transition to the affected community. The Company is committed to helping the local community transition to a new economic landscape after retirement.

Q. How will the Company provide that help?

A. The Company will develop a community transition plan that analyzes the economic strengths and weaknesses of the community that will affect the transition after the units are retired, as well as potential threats to the transition. This community transition plan will be closely coordinated with a communications strategy that will ensure that all relevant stakeholders are properly informed about the plan. Additionally, the Company has commissioned a detailed future-use study to analyze specific potential opportunities to redevelop the Karn site.

Q. Please explain the community transition plan for Karn Units 3 and 4.

A. The community transition plan for Karn Units 3 and 4 will be similar in intent to community transition plans that the Company developed for the retirement of the Karn Units 1 and 2 and the Classic 7. This transition will be updated by the Company subsequent to this filing. The transition plan will identify and describe the economic strengths of Bay County and advantages of the Karn site for future redevelopment, which would be explored in more detail in a future-use study. The transition plan also identifies economic weaknesses in the area and potential threats to redevelopment.

Q. Please describe the results of the Company's transition planning for retirement of the Classic 7.

A. The Company's transition plans for the Classic 7 focused on a smooth transition through open communication and regional sustainable vision alignment. The performance of future use studies along with collaboration with community stakeholders were critical to the Classic 7 decommissioning process. The Company's community partners included residents, government officials, state elected officials, economic development organizations, vendors, state agencies, and employees affected by the closure.

Q. How has the Company's community engagement resulted in success for the affected communities?

A. The Company's community engagement process at its Cobb plant, which is located at the Port of Muskegon, helped regional community leaders find new solutions to market and manage the port and re-imagine the potential for Muskegon Lake. Current plans include conversion of the area into a deep-water marine terminal. Similarly, the Company's stakeholder engagement process associated with the closing, near-complete demolition and active redevelopment of the Whiting plant will result in a site which is ideal for manufacturing and warehousing based upon its extensive logistical advantages such as rail and direct access to I-75.

Q. Please explain the community communication plan for Karn Units 3 and 4.

A. The Company began implementation of the communication plan as soon as the Company announced that it planned to retire Karn Units 3 and 4; this communication is the key first step in implementing the community transition plan, beginning the process of engaging stakeholders. Immediately prior to this filing, the Company notified all affected stakeholders of the retirement proposal, with the stakeholders including employees, local governments, community business leaders, local media, and local community organizations. Stakeholders also include State of Michigan government agencies and state and federal elected officials. The Company will be in communication throughout the retirement process with community stakeholders. All identified stakeholders will receive relevant communication at regular intervals from assigned Company representatives.

Q. Please explain the future-use study process for Karn Units 3 and 4.

A. The Company has been conducting a future-use study as part of its process for planning to retire Karn Units 1 and 2. These studies will consider environmental issues and local economic issues, such as real estate markets and demographics, and analyzed potential redevelopment options for each site. The retirement of all four Karn units in 2023 will un-restrain potential redevelopment options for the Karn site which is adjacent to the formerly retired Weadock site. Previous redevelopment options for the Weadock site were limited to reuse by the Company for other purposes. The Company will consider options for private redevelopment, as the retirement of Karn Units 1, 2, 3, & 4 may make more of the site, such as the port facilities, available for redevelopment.

Q. How will the retirement of Karn Units 3 and 4 in 2023 affect Company employees?

A. The employees that support the operation of Karn Units 1 and 2 as well as Karn Units 3 and 4 are Karn site employees. As such, all of the employees that directly support day-to-day facility operation were included in the Company's retention and separation program which was established to support the retirement of Karn Units 1 and 2 in 2023. The

Company continues to be committed to ensuring a smooth transition for the Karn employees as the decommissioning process for the Karn site is implemented.

<u>**Campbell Units 1, 2, and 3**</u>

Q. What is the tax impact of Campbell Units 1, 2, and 3?

A. The Company pays property taxes on Campbell Units 1, 2, and 3 that fund local governmental services provided by Port Sheldon Township and Ottawa County. The units' 2020 taxable valuation was $143.8 million, which is approximately 1.15% of the total taxable value in Ottawa County and 27% of the total taxable value in Port Sheldon Township. The units' 2021 taxable value declined by 12.5%, due to a decline in market conditions for coal-fired power plants. The overall taxable value of the Campbell site is expected to continue to decline due to negative market conditions facing coal-fired generation.

Q. Aside from property tax revenues, what other impacts will the retirement of Campbell Units 1, 2, and 3 in 2025 have on its respective community?

A. Coal-fired generation units provide employment in the communities in which they are located and can be significant local economic drivers. Retirement of Campbell Units 1, 2, and 3 in 2025 will bring economic transition to the affected community. The Company is committed to helping the local community transition to a new economic landscape after retirement.

Q. How will the Company provide that help?

A. The Company will develop a community transition plan that analyzes the economic strengths and weaknesses of the community that will affect the transition after the units are retired, as well as potential threats to the transition. This community transition plan will be closely coordinated with a communications strategy that will ensure that all relevant stakeholders are properly informed about the plan. Additionally, the Company plans to complete a detailed future-use study to analyze specific potential opportunities to redevelop the Campbell site.

Q. Please explain the community transition plan.

A. The community transition plan for Campbell Units 1, 2, and 3 will be similar in intent to community transition plans that the Company developed for the retirement of the Karn Units 1 and 2 and the Classic 7. The transition plan will identify and describe the economic strengths of Ottawa County and advantages of the Campbell site for future redevelopment, which would be explored in more detail in a future-use study. The transition plan also identifies economic weaknesses in the area, and potential threats to redevelopment.

Q. Please explain the community communication plan.

A. The Company began implementation of the communication plan as soon as the Company announced that it planned to retire Campbell Units 1, 2, and 3; this communication is the key first step in implementing the community transition plan, beginning the process of engaging stakeholders. Immediately prior to this filing, the Company notified all affected stakeholders of the retirement proposal, with the stakeholders including employees, local governments, community business leaders, local media, and local community organizations. Stakeholders also include State of Michigan government agencies and state and federal elected officials. The Company will be in communication throughout the retirement process with community stakeholders. All identified stakeholders will receive relevant communication at regular intervals from assigned Company representatives.

Q. Please explain the future-use study process.

A. The Company previously developed future-use studies as part of its process for retiring the Classic 7 and, as previously mentioned, is in the process of conducting a future use study for the Karn site. These studies considered environmental issues and local economic issues, such as real estate markets and demographics, and analyzed potential redevelopment options for each site. Because the Company intends to retire the Campbell site in its entirety, the potential redevelopment options are less restrained than if only one or two of the three units were retired.

Q. How many employees does the Company currently have at the Campbell site?

A. The Campbell site currently has 405 employees at the Campbell site, 313 of whom directly support day-to-day facility operation, with representatives of the Company's Generation Operations, Generation Engineering, Environmental, and other groups. Within the total number of 313 employees that directly support day-to-day facility operation, 214 employees are operations, maintenance, and construction ("OM&C") employees, 75 are exempt employees, and 24 are non-exempt employees. Employees in executive, manager and supervisor, professional, and outside sales positions are considered by the Company to be *exempt* from the Fair Labor Standards Act's minimum wage, overtime pay, and certain record-keeping requirements, and are considered at-will employees. Employees who work as technicians, office and clerical staff, and administrative support are considered *not to be exempt* from those requirements. OM&C employees at the Campbell site are represented by the Utility Workers Union of America ("UWUA").

Q. How will the retirement of the Campbell site in 2025 affect Company employees?

A. The Company is committed to ensuring a smooth transition for employees as the decommissioning process for Campbell is implemented. The Company will use regular and transparent internal communications with its employees to ensure that employees are informed about the Company's plans. The Company will leverage the lessons it learned from its successful experience in retiring the Classic 7 and planning for retirement of Karn Units 1 and 2 in developing a retention and separation plan to govern how employees are treated during the decommissioning process of Campbell Units.

Q. What is the Company's intended timing for its retention and separation plan?

A. Once a retirement date for the Campbell site is established, pursuant to an MPSC order in this case, the Company will implement a retention plan that takes effect 40 months prior to that retirement date. For example, if the Campbell Units are scheduled to complete their cold and dark activities by October 31, 2025, then the retention plan would go into effect on July 1, 2022. The retention plan for OM&C employees was previously negotiated with the UWUA and approved by Company leadership; retention plans for other classifications of employees have been developed by the Company, as well. The separation plan exists within current Company agreements and policies and would take effect when the Campbell site retires.

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 the Campbell site through the site's retirement date to ensure safe and reliable operations. Once a retirement date for the Campbell site is confirmed, some employees may seek employment at other Company locations or outside of the Company; meanwhile, hiring new employees at the Campbell site will become more difficult given the short remaining lifespan of the units, plus the training time necessary for any new hires is challenging. Using the best practices that the Company employed in retiring the Classic 7 and planning for the retirement of Karn Units 1 and 2, the Company plans to offer retention bonuses to all impacted employees who stay at the Campbell site for the entire 40-month period noted above.

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

A. When the Campbell site is 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 with the Company within 30 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; relocation policies for OM&C employees are explained in further detail below.

Q. What are the estimated costs of the retention and separation plan?

A. Based on current employment levels and demographics, the Company estimates the costs of this retention program, including estimated severance and moving cost, is $60 million if all employees qualify for the retention bonus and all retirement-eligible employees accept a severance offer. It is the Company's intent to find placements for as many employees as possible, thus mitigating the cost of separations.

Q. Is the Company requesting recovery of the retention incentive costs in this proceeding?

A. Yes. As discussed by Company Witness Jason R. Coker, the Company is requesting the expense recognition to be deferred as a regulatory asset until such time that the expenses are recovered in rates.

Q. What is the possible impact to affected employees at the Campbell site?

A. The Company expects that approximately 313 employees will be needed to continue operation of the Campbell site until its proposed retirement in 2025. The rest of the employees will be covered by the policy relevant to their classification. The Working Agreement covering OM&C employees guarantees all eligible OM&C employees a position at their current respective wage within 60 miles of the Campbell site. It is the Company's intent that all exempt and non-exempt employees, who desire to retain employment with the Company, will be offered another position. However, in the event that exempt or non-exempt employees cannot find placement within the Company, they will be offered involuntary severance in accordance with the terms of the Salaried Separation Plan. The Company has 7 locations within 60 miles of the Campbell site.

Q. What is the Company's recent history with managing employee impacts following the retirement of a coal-fired power plant?

A. Following the retirement of the Classic 7 in 2016, all Company employees who desired to continue employment with the Company were able to do so. The Company believes that this demonstrates the Company's commitment to its employees. The retirement of the

Classic 7 was successful because all employees had confidence that they would maintain secure employment following plant closure. As described earlier in my direct testimony, maintaining this confidence is essential for mitigating the Company's execution risk in retiring the Campbell site.

Q. How much time is needed for the Company to execute its plan for employees?

A. As discussed above, the Company plans for its retention plan to cover a 40-month period, preceded by negotiation and approval. This period of time is particularly necessary because many employees will need to be retrained for new jobs. When the Company retired the Classic 7, many operators were able to move to other coal-fired facilities within the Company, limiting the need for retraining. Since the Company plans to retire all of its remaining coal-fired units, this option is no longer available. Furthermore, the 7 Company locations within 60 miles of the Campbell site consist of numerous service centers, where the work is substantially different than at a generating site. Employees from the Campbell site who move, for example, to the West Kent Service Center may need several months of training to become certified in the distribution maintenance work done at that location. The Company's goal is to facilitate a smooth transition by having employees trained to move into new positions as soon as possible after the retirement of the Campbell site. The Company is capable of managing this transition, having done so with the Classic 7, but it needs sufficient time for workforce planning as well to ensure that appropriate positions are available for employees.

Q. To minimize retraining, could the Company relocate employees from the Campbell site to the Covert site?

A. Yes. The Covert site is within 60 miles of the Campbell site. While gas and coal generating plants are operated differently, there are many similarities with respect to maintenance which could allow for a relatively smooth transition for some Campbell employees. To the extent that employees relocate to locations which are not within a 60 mile radius of the Campbell site, the Company's Working Agreement covering OM&C employees allows those employees to receive Company-paid moving expenses if they accept a position more than 60 miles away, and the Company is providing an additional relocation incentive for employees moving more than 60 miles.

Q. Does this conclude your direct testimony?

A. Yes.

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 Approval of an Integrated Resource Plan	)	Case No. U-21090
under MCL 460.6t, certain accounting	)	
approvals, and for other relief.	)	
______________________________________	)	

DIRECT TESTIMONY

OF

BRIAN D. GALLAWAY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

Q. Would you please state your name and business address?

A. My name is Brian D. Gallaway, and my business address is 1945 Parnall Rd, Jackson, Michigan 49201.

Q. By who are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Executive Director of Fossil Fuel Supply in the Energy Supply Operations Department.

Q. Would you please describe your educational background and business experience?

A. I graduated in 1979 with a Bachelor of Science Degree in Electrical Engineering and in 2001 with a Master's Degree in Business Administration, both from Michigan State University. I have been employed by Consumers Energy since 1979. I have held a variety of engineering, operating, and supervisory positions in departments involved with the operation of the electric system and with the economic operation of the Company's generating plants. In 2002, I joined the Fossil Fuel Supply area in the Energy Supply Department as Fuels Transportation and Planning Director and in July 2011, I became the Executive Director of Fossil Fuel Supply in what is now the Energy Supply Department.

Q. What are your responsibilities as Executive Director of Fossil Fuel Supply?

A. I am responsible for procuring, transporting, and maintaining inventories for coal, natural gas, and oil in sufficient quantity and quality to meet Consumers Energy's electric generating needs in an efficient and economic manner.

Q. Have you ever appeared in any proceedings before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I submitted testimony in:

- Case No. U-13917 (direct), the Company's 2004 Power Supply Cost Recovery ("PSCR") Plan regarding costs of coal, oil, and natural gas used for electric generation for 2004;

- Case No. U-14274 (direct), the Company's 2005 PSCR Plan regarding costs of coal, oil, and natural gas used for electric generation for 2005;

- Case No. U-14347 (direct), the Company's 2004 General Rate Case regarding costs of coal, oil, and natural gas used for electric generation;

- Case No. U-14701 (direct, supplemental, and rebuttal), the Company's 2006 PSCR Plan regarding costs of coal, oil, and natural gas used for electric generation for 2006;

- Case No. U-15001 (direct), the Company's 2007 PSCR Plan regarding costs of coal, oil, and natural gas used for electric generation for 2007;

- Case No. U-15415 (direct), the Company's 2008 PSCR Plan regarding costs of coal, oil, and natural gas used for electric generation for 2008;

- Case No. U-15675 (direct), the Company's 2009 PSCR Plan regarding costs of coal, oil, and natural gas used for electric generation for 2009;

- Case No. U-16045 (direct and rebuttal), the Company's 2010 PSCR Plan regarding costs of coal, oil, and natural gas used for electric generation for 2010;

- Case No. U-16432 (direct, rebuttal, and second rebuttal), the Company's 2011 PSCR Plan regarding costs of coal, oil, and natural gas used for electric generation for 2011;

- Case No. U-16890 (direct and rebuttal), the Company's 2012 PSCR Plan regarding costs of coal, oil, and natural gas used for electric generation for 2012;

- Case No. U-17317-R (direct and rebuttal), the Company's 2014 PSCR Reconciliation regarding the situations that made it necessary for the Company to unexpectedly conserve coal during 2014, resulting in higher than planned PSCR expense for 2014;

- Case No. U-17678 (rebuttal), the Company's 2015 PSCR Plan regarding alleged failure to consider coal transportation and delivery issues in Consumers Energy's 2015 PSCR Plan case filing;

- Case No. U-17429 (direct), the Company's Application for approval of a Certificate of Necessity for the Thetford Generating Plant pursuant to MCL 460.6s and for related accounting and ratemaking authorizations; and

- Case No. U-20165 (direct), the Company's Application for approval of an Integrated Resource Plan ("IRP") under MCL 460.6t and for other relief.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to discuss the fossil fuel price forecasts used in the Company's IRP. Specifically, my direct testimony addresses:

- The Company's current fuel procurement and supply arrangements, as well as the projected fuel costs, for the Company's existing generating facilities;
- The commodity pricing used in the IRP to evaluate options to meet Consumers Energy's projected capacity needs for the period 2022 – 2040; and
- The Company's anticipated fuel procurement and supply arrangements, as well as the projected fuel costs, for the future Company fossil generating facilities identified in the Proposed Course of Action ("PCA")

Q. Are you including any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-61 (BDG-1)	Consumers Energy Company Existing Fossil Generating Facilities;
Exhibit A-62 (BDG-2)	Third Party Henry Hub Gas Forecasts & Composite Price Forecast;
Exhibit A-63 (BDG-3)	Henry Hub Natural Gas Price Forecast for 2020-2040;
Exhibit A-64 (BDG-4)	Henry Hub Natural Gas Price Forecast for 2020-2040 (Including Seasonality);
Exhibit A-65 (BDG-5)	EIA Natural Gas Historical Price Forecast 2010-2021;
Exhibit A-66 (BDG-6)	Third Party Crude Oil Forecasts & Composite Price Forecast;
Exhibit A-67 (BDG-7)	Third Party CAPP Eastern Coal & Composite Price Forecast;
Exhibit A-68 (BDG-8)	Third Party PRB Western Coal & Composite Price Forecast;
Exhibit A-69 (BDG-9)	J.H. Campbell Delivered Coal Price Forecast;

Exhibit A-70 (BDG-10)	D.E. Karn Delivered Coal Price Forecast;
Exhibit A-71 (BDG-11)	Zeeland Delivered Natural Gas Price Forecast;
Exhibit A-72 (BDG-12)	Jackson Delivered Natural Gas Price Forecast;
Exhibit A-73 (BDG-13)	Karn Delivered Natural Gas Price Forecast; and
Exhibit A-74 (BDG-14)	New Plant Delivered Natural Gas Price Forecast.

Q. Were these exhibits and your direct testimony prepared by you or under your direction and supervision?

A. Yes.

SECTION I: CONSUMERS ENERGY'S EXISTING GENERATING FACILITIES

Q. Please describe Consumers Energy's portfolio of generating facilities for which fossil fuel is procured.

A. The list of Consumers Energy's existing fossil fueled generating facilities is shown in Exhibit A-61 (BDG-1).

Q. How does the Company procure fuel supply for its existing coal fired generating facilities?

A. Consumers Energy's coal fired generating plants were originally designed to burn Central Appalachia ("CAPP") bituminous coal. In 1988, the Company began burning Powder River Basin ("PRB") sub-bituminous coal to take advantage of more favorable emissions and pricing compared to CAPP bituminous coal. As a result, Company generating plants now burn primarily PRB coal, but can burn a blend of coals from both sources in an effort to maximize capacity, minimize production costs, and meet regulatory requirements. Consumers Energy manages price and supply risk for its coal fired generation fleet by managing a portfolio of multi-year, annual, quarterly, and sometimes monthly coal purchase contracts. This strategy provides for a secure supply of coal by purchasing most of the Company's coal requirements well in advance of the anticipated burn under multi-year and annual agreements while leaving the remaining coal requirements to be purchased on a spot basis. The shorter-term spot purchases provide the Company with the ability to adjust to overall requirements as generating unit coal blends and operations change throughout the year as well as provide the flexibility to take advantage of favorable market conditions. In addition to managing a portfolio of coal supply contracts, the Company also manages coal transportation contracts with the various carriers of bulk commodities to the generating facilities. This includes both rail and vessel.

Q. How does the Company procure fuel supply for its existing oil and natural gas fired generating facilities?

A. The fuel procurement process utilized by Consumers Energy is plant dependent. For example, the D.E. Karn ("Karn") 3 and 4 generating units are large steam turbine generators fueled by natural gas or oil or a blend of the two, providing the ability to operationally hedge the price of either fuel against the other. The Company has two natural gas sources for Karn Units 3 and 4 – one from Consumers Energy's natural gas distribution system and one from DTE Gas Company's northern Michigan gathering system through the DCP Bay Area Pipeline. Natural gas for Karn Units 3 and 4 is purchased on a spot basis. Karn Units 3 and 4 also have storage tanks that allow these units to have an oil inventory. These storage tanks allow Karn Units 3 and 4 to burn oil from inventory and replenish that oil on the spot market when market prices are favorable.

The Zeeland Generating Station ("Zeeland Plant") consists of two simple-cycle gas combustion turbines and a combined-cycle natural gas fired generating plant. Natural gas is supplied to the Zeeland Plant from the ANR Pipeline gas transmission system ("ANR") via a 7.5 mile lateral owned and operated by SEMCO Energy Gas Company ("SEMCO"). The Company currently utilizes a gas management services agent ("Agent"), pursuant to a gas management services agreement, whose contractual obligation is to procure and deliver gas when needed on a firm basis to the SEMCO interconnection. The Company also has a transportation services contract in place with SEMCO that provides for firm transportation from the ANR pipeline interconnection to the Zeeland Plant.

The Jackson Generating Plant ("Jackson Plant") is a combined-cycle natural gas fired generating plant. The plant receives its natural gas supply from the Vector pipeline system through a lateral pipeline owned and operated by the Consumers Energy natural gas utility. Similar to the Zeeland Plant gas management services agreement, the Company utilizes a third-party Agent to manage the gas supply for the Jackson Plant.

Q. Why does the company utilize a third-party Agent to provide the gas supply for the Zeeland and Jackson plants?

A. The company utilizes Agents for those plants that are not connected directly to a gas utility distribution system where a large volume transportation tariff that provides balancing and storage exists or it does not hold firm transportation, balancing, or storage arrangements on the transmission pipeline to which the plant is connected. Entering into an agreement with an Agent allows the Company to take advantage of the Agent's diversity of gas purchasing/transportation contracts, gas purchasing experience, as well as the portfolio of arrangements the Agent has with the gas transmission pipeline companies more economically than if the Company were required to obtain firm transportation and storage directly from the gas transmission pipeline companies.

SECTION II: COMMODITY PRICE FORECASTS USED IN THE DEVELOPMENT OF THE IRP

Natural Gas

Q. What is the Henry Hub?

A. The Henry Hub is a point on the natural gas system located in Erath, Louisiana, used as a pricing point for natural gas futures contracts traded on the New York Mercantile Exchange ("NYMEX").

Q. What Henry Hub natural gas forecasts have been prepared for use in this IRP?

A. Four natural gas forecasts have been included in this IRP:

1. Consumers Energy's internal Business As Usual ("BAU") forecast utilizing third-party sources;
2. U.S. Energy Information Administration's ("EIA") 2020 Annual Energy Outlook ("AEO") "Reference" case Henry Hub forecast;
3. EIA 2020 AEO Reference case Henry Hub forecast, 200% Sensitivity; and
4. EIA 2020 AEO "High Oil and Gas Supply" case Henry Hub forecast.

Each of these cases are explained in further detail below.

Q. Please explain the basis of the Consumers Energy BAU ("CE BAU") natural gas price forecast used in the IRP.

A. The CE BAU is the same Henry Hub natural gas price nominal forecast used in the Company's internal studies as well as its PSCR filings. The Company acquired three long-term natural gas price forecasts and one short-term natural gas price forecast to develop a composite Henry Hub natural gas price forecast for 2020 through 2040. The long-term 2026 through 2040 natural gas price forecasts acquired include the IHS Market ("IHS") May 2019 forecast; the EIA January 2020 AEO Reference case forecast; and Energy Ventures Analysis, Inc.'s ("EVA") November 2019 forecast. The short-term 2020 through 2025 natural gas price forecast was acquired from the NYMEX on January 29, 2020. The Consumers Energy annual Henry Hub natural gas composite price forecast used in the IRP is the NYMEX future prices for the short term (2020 through 2025) and a weighted average incremental escalation of the three long-term price forecasts applied to the years following the five-year futures contracts traded on the NYMEX for the long term (2026 through 2040). Exhibit A-62 (BDG-2) shows the three third-party forecasts as well as the Company's resulting annual composite forecast derived from the third-party forecasts.

Q. Why does the Company use this type of forecast?

A. First and foremost, the Company believes in utilizing the most reasonable and accurate fuel forecasts in its studies. Inasmuch as no entity has the necessary skills or ability to prepare a perfectly accurate forecast, the Company creates a composite fuel price forecast taking into account the expertise and opinions of different well known industry forecast sources as well as the market forwards which are reflective of actual transactions. Using an average incremental increase and applying it to the latest five-year futures contract traded on NYMEX allows the Company to rebase the vintage third-party forecast to the current period yet utilize their escalations in a composite manner. In addition, using this approach introduces the analysis of several different, reputable, and independent expert viewpoints into the forecast.

Q. Please explain the basis of the EIA AEO Reference case ("AEO Reference") natural gas price forecast used in the IRP.

A. The AEO Reference forecast utilizes, as its base, the EIA's Henry Hub forecast found in the 2020 EIA AEO, Table 13 reference cases, for 2020 through 2040. Exhibit A-63

(BDG-3) shows the AEO Reference forecast in addition to the other Henry Hub forecasts utilized in this IRP.

Q. Why did the Company select this forecast for use in its IRP?

A. The Commission ordered the use of the EIA AEO forecast in its modeling parameters described in Case No. U-18418.

Q. Please explain the basis of the EIA AEO Reference case 200% Sensitivity ("AEO 200% Sensitivity") natural gas price forecast used in the IRP.

A. The AEO 200% Sensitivity forecast utilizes a scaled variation of the AEO Reference forecast. The annual values for this forecast were derived by linearly interpolating between the AEO Reference forecast value for 2020 and 200% of the AEO Reference forecast value for 2040. Exhibit A-63 (BDG-3) shows the AEO 200% Sensitivity forecast in addition to the other Henry Hub forecasts utilized in this IRP.

Q. Why did the Company select this forecast for use in its IRP?

A. The Commission ordered the use of a 200% forecast in its modeling parameters described in Case No. U-18418.

Q. Please explain the basis of the EIA AEO High Oil & Gas Supply ("AEO High Oil & Gas Supply") natural gas price forecast used in the IRP.

A. The AEO High Oil & Gas Supply forecast is based on the EIA 2020 AEO "High Oil and Gas Supply" side case. Compared with the AEO Reference case, the High Oil and Gas Supply case reflects lower costs and greater U.S. oil and natural gas resource availability due in part to the higher adoption of renewable resources, which allows more production at lower prices. Exhibit A-63 (BDG-3) shows the AEO High Oil & Gas Supply forecast in addition to the other Henry Hub forecasts utilized in this IRP.

Q. Why did the Company select this forecast for use in its IRP?

A. The Company selected this EIA forecast to use in its IRP Advanced Technology sensitivity as it both reflects lower renewable costs and a higher adoption of renewables.

Q. Have any modifications been made to these forecasts prior to its use in the analyses in this IRP?

A. Yes. All these forecasts are annual forecasts and do not recognize the variations in gas prices that typically occur on a monthly basis during the year. To account for this fact, and to allow the Aurora model to better predict the utilization of the generation resources that utilize natural gas as a fuel source, the Company introduced "seasonality" into each Henry Hub forecast. This "seasonality" is based on the actual differences in gas prices to be above or below the annual average for the winter period, the spring and fall periods, and the summer period. Exhibit A-64 (BDG-4) is identical to Exhibit A-63 (BDG-3) except to show each forecast with the effects of seasonality introduced. Though the graph shows the seasonality impacts that have been introduced, the average of the monthly prices for each year in each forecast is identical to that in the original annual forecast.

Q. What are the risks associated with relying on a single forecast, as the Company is doing in relying on the EIA AEO for its Henry Hub forecast?

A. Relying on a single source, without consideration for how that source has performed historically or without validation of the assumptions that source is relying on for the future, can lead to decisions that can have substantial negative financial impact to Consumers Energy's electric ratepayers for years to come. As an example, Exhibit A-65 (BDG-5) shows 12 years of EIA natural gas price forecasts. The exhibit illustrates that these forecasts have been historically high. The 2010 EIA forecast for the year 2020 was approximately 300% higher than the actual prices experienced. If decisions had been made ten years ago with sole reliance on the 2010 EIA AEO, such as a fuel or a purchase power decision, the Company's electric ratepayers could be paying 300% more than necessary. As opposed to relying on one forecast, the Company prudently uses a blend of market forwards to reflect actual trades and a composite of several forecasts to provide what it believes to be a more accurate representation of future prices, and to lower the price risk to its customers.

Q. How were these natural gas forecasts used to develop a delivered natural gas cost to each of the Company's generating plants?

A. For Karn Units 3 and 4, the Company included the costs of its current contracts with the Consumers Energy natural gas utility, DTE Gas Company, and DCP Midstream, with appropriate escalations to advance those agreements beyond the time they are set to expire, and to the point they are set to cease operation in the IRP. A combination of firm and interruptible transport is provided for in these agreements.

For the Zeeland Plant, the Company included the costs of its current contracts with its Agent and SEMCO with appropriate escalations to advance those agreements beyond the time they are set to expire, and to the point they are set to cease operation in the IRP. Firm or secondary firm gas transportation is a requirement of the Agent the Company utilizes to provide gas to the SEMCO interconnection point with the ANR pipeline.

For the Jackson Plant, the Company included the costs of its current contracts with its Agent and the Consumers Energy natural gas utility with appropriate escalations to advance those agreements beyond the time they are set to expire, and to the point they are set to cease operation in the IRP. Firm or secondary firm gas transportation is a requirement of the Agent the Company utilizes to provide gas to the Consumers Energy interconnection point with the Vector pipeline.

Exhibits A-71 (BDG-11) through A-73 (BDG-13) show the delivered natural gas price forecasts used in the IRP analysis for the Zeeland plant, Jackson plant, and Karn 3 and 4, respectively.

Q. How did the Company determine a delivered natural gas price for a potential new utility-owned generating plant?

A. For any new Company-owned gas plant, the Company assumed that the plant would be connected to the Company's gas transmission system with the same firm gas transportation structure that would have existed for the proposed Thetford Plant in 2013, had that plant been approved and built. It is anticipated that a new gas plant, either combustion turbine or natural gas combined cycle would be serviced under the Consumers Energy Gas Transportation Service Rate XLT, negotiated for high volume. Natural gas storage for this facility, or other future gas fired generating plants, is available through the XLT tariff, to ensure adequate natural gas supply is available whenever Consumers Energy's natural gas fired generation fleet is called upon to operate. The storage available under the XLT tariff aids in balancing the supply purchases to the actual fuel consumption at the new plant and will help ensure an adequate supply of fuel at competitive prices. Also, if the utilization of the new plant becomes very high, an increase in the annual contract quantity, under the XLT tariff, could be made which would result in an increase in the amount of storage allocated for the facility. Storage provides a more secure supply of fuel through a larger available fuel inventory, with less price sensitivity to the market, and in a manner similar to the way the Company currently manages its coal purchases and inventories. Exhibit

A-74 (BDG-14) shows the delivered natural gas price forecast used in the IRP analysis for a potential new Company-owned natural gas plant.

Q. What are the Company's projected long-term firm gas transportation or natural gas storage contracts that the utility will hold to provide an adequate supply of natural gas to its new or existing generation facilities?

A. As mentioned above, for existing Company-owned gas plants, the Company would have arrangements with third parties who can provide firm transportation on the pipeline to which the plant is connected. For a new gas plant, the Company would connect to the Company's gas transmission system. The Company's gas transmission system contains large amounts of storage capacity. A portion of this storage capacity is made available as part of, and included with, the XLT Tariff. The Company's gas transmission system is also connected to several large interstate gas transmission pipeline systems (ANR, Great Lakes, Vector, and Panhandle Eastern) that enable it to have access to the more traditional sources of natural gas (the Gulf Coast, Texas, Louisiana, Kansas, Oklahoma, Canada, and Michigan) as well as the recently developed and rapidly expanding shale plays.

<u>Oil</u>

Q. Please explain the oil price forecast used in the IRP.

A. Similar to the approach to the development of the natural gas price forecast, Consumers Energy acquired four long-term crude oil price forecasts and one short-term crude oil price forecast and used them to develop a composite crude oil price forecast for 2020 through 2040. The long-term crude oil price forecasts acquired include IHS's May 2019 forecast; EIA's January 2020 AEO forecast; JD Energy's November 2018 forecast; and EVA's November 2019 forecast. The short-term crude oil price forecast was acquired from

NYMEX. Consumers Energy's annual crude oil composite price forecast is the average of the monthly values for each respective year of the NYMEX future prices for the near term (2020 through 2025), and a weighted average incremental increase of the four long-term price forecasts applied to the years following the five-year NYMEX future prices for the long term (2026 through 2040). Exhibit A-66 (BDG-6) shows the four third-party forecasts as well as the Company's annual crude oil composite forecast derived from the third-party forecasts, designated as "CE BAU" in the exhibit.

Q. Does the Company utilize a composite oil price forecast for any other purposes?

A. Yes. The Company utilizes a composite oil price forecast for internal studies and its annual PSCR Plan filings before the Commission.

Q. Does the Company provide a delivered oil price to existing and new utility-owned generating plants?

A. Yes. The price relationships that have been developed between crude oil and the No. 6 and No. 2 oils that the Company's facilities utilize includes the cost of transportation. The Company did not include a delivered oil price to a new utility-owned generating plant in its IRP analysis because the Company is not proposing to build a generating plant which utilizes oil for fuel.

<u>Coal</u>

Q. Please explain the BAU coal forecast used in the IRP for the Company's existing coal generating units?

A. The Company's coal generating units burn various blends of CAPP bituminous coal and PRB sub-bituminous coal. Consumers Energy monitors near-term market prices based on actual trading and long-term mine mouth price forecasts for CAPP bituminous coal and

Southern PRB sub-bituminous coal. The four long-term mine mouth price forecasts utilized were from IHS, EIA, EVA, and JD Energy. A composite mine mouth price forecast was developed using the Company's knowledge of actual market activity for the near term (2020 through 2022), a weighted average of the four long-term forecasts for the long term (2025 through 2040), and linear escalation between the short-term and long-term forecasts to develop a mid-term period (2023 through 2024). Exhibit A-67 (BDG-7) and Exhibit A-68 (BDG-8) show the four third-party forecasts as well as the Company's annual composite forecast derived from the third-party forecasts for CAPP bituminous coal and PRB sub-bituminous coal, respectively, and designated as "CE BAU" in the exhibits.

Q. Does the Company utilize a composite coal price forecast for any other purposes?

A. Yes. The Company utilizes a composite coal price forecast for its internal studies and its annual PSCR Plan filings before the Commission.

Q. How were these coal forecasts used to develop a delivered coal cost to each of the Company's generating plants?

A. Coal transportation costs (rail and vessel, including railcar costs) were projected specific to each existing Consumers Energy coal fired generating plant. These transportation costs were added to the mine mouth composite price forecasts to produce delivered coal price forecasts for each existing Consumers Energy coal fired generating plant. The transportation costs were developed using existing Consumers Energy transportation contract pricing and expected pricing in the near term. The near-term transportation costs were escalated at the quarterly trend of the All Inclusive Index – Less Fuel ("AII-LF") and a monthly mileage-based fuel surcharge was added to achieve long-term transportation costs through the Planning Period. The AII-LF is a rail industry price index that measures changes in the price level of inputs to railroad operations without the influence of fuel costs. The AII-LF is published quarterly by the Association of American Railroads and approved by the Surface Transportation Board. Exhibits A-69 (BDG-9) through A-70 (BDG-10) show the delivered coal price forecasts used in the IRP analysis for the Company's existing coal fired generating units, designated as "CE BAU" in the exhibits.

Q. How did the Company determine a delivered coal price for a potential new utility-owned generating plant?

A, The Company did not include a delivered coal price for a new utility-owned generating plant in its IRP analysis because the Company is not proposing to build a new coal fired generating plant.

<u>SECTION III: RETIREMENT OF KARN UNITS 1 AND 2, KARN UNITS 3 AND 4, AND J.H. CAMPBELL UNITS 1, 2, AND 3</u>

Q. The Company's PCA includes the retirement of Karn Units 1 and 2 in 2023 and J.H. Campbell ("Campbell") Units 1, 2, and 3 in 2025. How do these decisions impact the Company's coal purchasing strategy for these units?

A. The decision to retire Karn Units 1 and 2 in 2023, as approved in the Company's 2018 IRP Case No. U-20165, and Campbell Units 1, 2, and 3 in 2025 will have no impact on the Company's coal purchasing strategy. The Company secures coal for its coal fired generating units in order to minimize price risk to its customers, protect it from price volatility in the market, and mitigate supply risk to its customers. The Company purchases quantities of coal over time that typically positions it to have approximately 70% to 90% of its anticipated total volume secured by the fall of each year for the following calendar year, approximately 40% to 50% secured for the second calendar year, and approximately 20% to 25% secured for the third calendar year. Since there are no changes in the proposed retirement of Karn Units 1 and 2 since the last IRP, the Company has already included the impacts of these retirements in its coal purchasing strategy. As well, the proposed retirement of Campbell Units 1, 2, and 3 in 2025 does not impact the coal purchasing strategy as the strategy allows for the gradual reduction in coal purchases to ensure there is a sufficient supply of coal to operate until the time of retirement and at the same time, minimize the risk of any stranded coal inventory.

Q. Besides coal supply, are there other coal related commitments that could be impacted by the proposed retirement of these units?

A. At the present time, there are no contractual commitments for coal transportation, railcar supply, coal testing, or anything else coal related, beyond the proposed retirement of Campbell Units 1 through 3 in 2025. Any new contractual commitments for these necessary services will be arranged for with the flexibility necessary to ensure a reliable and economic supply of fuel up to the point of retirement.

Q. The Company's PCA also includes the retirement of Karn Units 3 and 4 in 2023. How does this decision impact the Company's fuel purchasing strategy for these units?

A. All the oil and gas required to operate these units is purchased on the spot market. There are no contractual commitments for either oil or gas. The retirement of these units will not impact the fuel purchasing strategy.

Q. Besides fuel supply, are there other oil or gas related commitments that could be impacted by the proposed retirement of these units?

A. No. All existing agreements have provisions that will not impact the proposed retirement of Karn 3 and 4 in 2023.

SECTION IV: PROJECTED ANNUAL FUEL COSTS UNDER VARIOUS SCENARIOS

Q. What are the projected annual fuel costs under the various scenarios modeled by the Company in the development of its IRP?

A. Company witness Sara T. Walz provides the projected annual fuel costs under the various scenarios modeled by the Company in the development of its IRP.

SECTION V: EXPECTED FUEL TYPE, SUPPLY, COSTS, AND CONTRACTUAL ARRANGEMENTS ASSOCIATED WITH THE PCA

Q. Has the Company identified specific new generation additions in its PCA to fulfil its capacity requirements and to support the accelerated retirement of Karn Units 3 and 4 in 2023 and Campbell Units 1, 2, and 3 in 2025?

A. Yes. The Company has proposed and is pursuing the purchase of four existing gas fired generation facilities:

- New Covert Generating Facility ("Covert Plant");
- Dearborn Industrial Generation ("DIG Plant");
- Livingston Generation Station ("Livingston Plant"); and
- Kalamazoo River Generating Station ("Kalamazoo Plant").

Q. Please describe the fuel used for the Covert Plant and the plans or provisions for purchasing and transporting fuel to the plant.

A. The Covert Plant is a natural gas fired generating facility connected to ANR through a 3.5 mile long, 20" lateral owned and operated by ANR. Consistent with that of the current owner, and also consistent with how the Company currently provides gas to its Zeeland and Jackson plants, the Company expects to use an Agent to provide an economic and firm supply of gas directly to the plant. The Agent will be responsible for purchasing gas on the spot market and delivery of physical gas to the plant interconnection point, utilizing its assets to appropriately schedule and balance gas purchases with actual plant burn.

Q. Please describe the fuel used for the DIG Plant and the plans or provisions for purchasing and transporting fuel to the plant.

A. The DIG Plant is a natural gas fired generating facility connected to the DTE Gas Company distribution system. The DIG Plant is currently a DTE Gas Company transportation customer under its applicable XXLT tariff. It is expected that it would remain under this tariff once ownership is assumed by the Company. Rather than use an Agent for the physical gas purchases like proposed for Covert, the Company expects to make the gas purchases in-house, utilizing the provisions included with the XXLT tariff to perform the storage and balancing functions.

Q. Please describe the fuel used for the Livingston Plant and the plans or provisions for purchasing and transporting fuel to the plant.

A. The Livingston Plant is a natural gas fired generating facility connected to the DTE Gas Company distribution system. The Livingston Plant is currently a DTE Gas Company transportation customer under its applicable XLT tariff. It is expected that it would remain under this tariff once ownership is assumed by the Company. Rather than use an Agent for the physical gas purchases like proposed for Covert, the Company expects to make the gas purchases in-house, utilizing the provisions included with the XLT tariff to perform the storage and balancing functions.

Q. Please describe the fuel used for the Kalamazoo Plant and the plans or provisions for purchasing and transporting fuel to the plant.

A. The Kalamazoo Plant is a natural gas fired generating facility connected to the Panhandle Eastern Gas Transmission System through a one mile long, 12" lateral owned and operated by the Consumers Energy gas utility. The Company expects to use an Agent to provide an economic and firm supply of gas to the Consumers Energy Gas utility-owned lateral, with firm transport on the Consumers Energy Gas utility lateral to the plant. The Agent will be responsible for purchasing gas on the spot market and delivery of physical gas on Panhandle Eastern to the plant interconnection point, utilizing its assets to appropriately schedule and balance gas purchases with actual plant burn. Depending on the Agent selected, the Company anticipates entering into, or assuming, an Enhanced Interruptible Transportation Agreement in conjunction with a Gas Parking Service Agreement as supplement to the Agent's assets.

Q. Why does the company plan to use a third-party Agent to provide the gas supply for the Covert and Kalamazoo plants?

A. These two plants are connected to ANR and Panhandle Eastern, respectively. Consistent with the approach the Company has taken to provide gas supply for the Zeeland and Jackson plants, the company utilizes Agents for those plants that are not connected directly to a gas utility distribution system where a large volume transportation tariff that provides balancing and storage exists or it does not hold firm transportation, balancing, or storage arrangements on the transmission pipeline to which the plant is connected. Entering into an agreement with an Agent allows the Company to take advantage of the Agent's diversity of gas purchasing/transportation contracts, gas purchasing experience, as well as the portfolio of arrangements the Agent has with the gas transmission pipeline companies more economically than if the Company were required to obtain firm transportation and storage directly from the gas transmission pipeline companies.

Q. What are the projected delivered fuel prices and annual fuel costs associated with the acquisition of these facilities in the Company's PCA?

A. Company witness Walz provides the projected delivered fuel prices and annual fuel costs in her testimony and exhibits.

<u>SECTION VI: SUMMARY</u>

Q. With respect to the fossil-fuel based generating resources discussed in your direct testimony, please summarize the expected fuel type, supply, costs, and contractual arrangements associated with the PCA.

A. The above direct testimony explains the Company's fuel type, current fuel procurement and supply arrangements, as well as the projected fuel costs for the Company's new and existing generating facilities. It includes the fuel costs used in the IRP to evaluate options to meet Consumers Energy's projected capacity need for the period 2022 through 2040.

My direct testimony also describes the commodity pricing developed for the BAU, or reference scenario, as well as the commodity prices developed and used in the alternative scenarios and sensitivities. Additionally, it includes the anticipated contractual arrangements for natural gas purchasing, transportation, and storage for the Company's new and existing generating plants. My direct testimony also describes the Company's decision to retire Karn Units 1 and 2 in 2023 and proposal to retire Karn Units 3 and 4 in 2023 and Campbell Units 1, 2, and 3 in 2025 and the lack of impact it would have on the Company's fuel purchasing strategy. Finally, my direct testimony addresses the fuel supply arrangements for the existing natural gas plants that the Company proposes to purchase as part of the PCA. In summary, this information along with the associated exhibits provided with my direct testimony fulfills the requirements of the IRP and the Company's PCA.

Q. Does this complete your direct testimony?

A. Yes, it does.

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 Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief. _______________________________________	))))))	Case No. U-21090

DIRECT TESTIMONY

OF

CAROLEE KVORIAK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

Q. Please state your name and business address.

A. My name is Carolee Kvoriak, and my business address is One Energy Plaza, 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 at Consumers Energy?

A. I currently hold the position of Executive Director of Tax.

Q. How long have you been employed with Consumers Energy?

A. I have been with the Company for 11 years.

Q. Please state your educational background and work experience.

A. I graduated from Wayne State University in May 1996 with a Bachelor of Arts Degree in Economics. I graduated from Wayne State University Law School in December 1999 and was admitted to the State Bar of Michigan in June 2000. I was a judicial clerk for the Honorable Marilyn Kelly of the Michigan Supreme Court from March 2000 to March 2001. In April 2001, I joined the law firm of Miller, Canfield, Paddock & Stone, PLC as an associate attorney in the Federal Tax Group. In February 2006, I joined the law firm of Honigman Miller Schwartz & Cohn LLP as an associate attorney in the Federal Tax Group. In October 2007, I joined Magna Services of America, Inc., a global "tier one" automotive supplier headquartered in Toronto, Canada with an office in Troy, Michigan, as a tax attorney. I received a Master of Laws in Taxation from Wayne State University Law School in May 2008. In April 2010, I joined Consumers Energy as a Senior Tax Attorney where I have had increasing levels of responsibility for the tax matters of the Company.

Q. Have you previously testified in any other Michigan Public Service Commission ("MPSC" or the "Commission") cases?

A. Yes. I testified in Case No. U-18250 in support of the proposed securitization of the Palisades Nuclear Plant power purchase agreement and in Case No. U-20165 in support of the Integrated Resource Plan ("IRP") filed in June 2018.

Q. Are you a member of any professional societies or organizations?

A. Yes, I am a member of the State Bar of Michigan.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to discuss the Production Tax Credit ("PTC") allowed under Section 45 of the Internal Revenue Code ("IRC"), the Investment Tax Credit ("ITC") allowed under Section 48 of the IRC, and other federal tax credits allowed for renewable and alternative technologies.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring:

Exhibit A-75(CK-1) Generation Operations - Property Tax.

<u>SECTION I: THE IRC SECTION 45 PTC</u>

Q. What is the PTC?

A. The PTC is a federal income tax credit enacted to incentivize the production of energy from renewable energy resources. It is set forth in Section 45 of the IRC, 26 USC 45 ("IRC 45").

Q. How is the PTC calculated?

A. The PTC for any taxable year is an amount equal to 1.5¢ (adjusted for inflation), the "PTC Rate", multiplied by the kilowatt hours of electricity produced by the taxpayer from qualified energy resources. For 2021, the PTC Rate is 2.5¢ per kilowatt of electricity produced.

Q. What resources are "qualified energy resources" for purposes of the PTC?

A. The following energy resources qualify for the PTC: wind, certain biomass, geothermal, small irrigation, municipal solid waste, qualified hydropower production, marine, and hydrokinetic energy. See IRC 45(a), (d). Solar projects placed in service after December 31, 2005 do not qualify for the PTC. See IRC 45(d)(4)(A).

Q. Do the wind energy parks currently owned by the Company qualify for the PTC?

A. Yes, all four wind energy parks qualify; however, the Company received a cash grant under Section 1603 of the American Recovery and Reinvestment Act of 2009, Public Law No. 111-5 ("ARRA") in lieu of the PTC for the Lake Winds Energy Park.

Q. Under current law, will future wind energy parks either constructed or acquired by the Company qualify for the PTC?

A. Potentially, but not at the full 100% PTC Rate. Wind projects for which construction has started before January 1, 2017 qualify for 100% of the PTC. Wind projects for which construction starts after January 1, 2017 but before January 1, 2022 still qualify for the PTC but at a reduced rate. Wind projects that start construction after January 1, 2017 but before January 1, 2018 qualify for 80% of the PTC. Wind projects that start construction after January 1, 2018 but before January 1, 2019 qualify for 60% of the PTC. Wind projects that start construction after January 1, 2019 but before January 1, 2020 qualify for 40% of the PTC. In December 2019, the Setting Every Community Up for Retirement Enhancement Act of 2019 further extended 60% PTC for wind projects that start construction after January 1, 2020 but before January 1, 2021. The Consolidated

Appropriation Act of 2021, enacted on December 24, 2020, further extended 60% PTC for projects that start construction after January 1, 2021 but before January 1, 2022. Wind projects that start construction on or after January 1, 2022 currently do not qualify for PTC. IRC 45(b)(5).

Q. Are there any proposed extensions of PTC for wind projects currently under consideration by Congress?

A. Yes. The Growing Renewable Energy and Efficiency Now Act of 2021 ("GREEN Act of 2021") would extend 60% PTC for wind projects that start construction before January 1, 2027. The Clean Energy for America Act of 2019, sponsored by the Chairman of the Senate Finance Committee, Senator Ron Wyden ("CEAA of 2019"), introduces a new PTC for all clean energy, including wind. Finally, President Biden's American Jobs Plan, introduced on March 31, 2021, calls for a 10-year extension and phase down of the PTC for clean energy generation.

Q. Do the solar energy installations currently owned by the Company qualify for the PTC?

A. No.

Q. When does the Company receive the benefit of the PTC?

A. As provided at IRC 45(a)(2)(A)(ii), the Company receives the PTC for the 10-year period beginning on the date the facility was originally placed in service.

Q. When do customers realize the benefit of the PTC?

A. Because the PTC is not subject to any normalization rules, customers realize the benefit of the PTC at the same time the Company does.

SECTION II: THE IRC SECTION 48 ITC

Q. What is the ITC?

A. The ITC is a federal income tax credit enacted to incentivize investment in energy property. It is set forth at Section 48 of the IRC, 26 USC 48 ("IRC 48").

Q. How is the ITC calculated?

A. The ITC is equal to 30% of the basis of energy property in the year such property is placed in service. See IRC 48(a)(2)(A)(i).

Q. What is "energy property" for purposes of the ITC?

A. The following property is "energy property" for purposes of the ITC: certain solar energy equipment, qualified fuel cell property or qualified microturbine property, combined heat and solar system property, qualified small energy wind property, and geothermal energy equipment. IRC 48(a)(3). The property must also be depreciable under the IRC. IRC 48(a)(3)(B)(ii). In addition, taxpayers may elect to take ITC in lieu of PTC for projects that would otherwise qualify for the PTC. IRC 48(a)(5)(A).

Q. Do the wind energy parks currently owned by the Company qualify for the ITC?

A. Yes, all four wind energy parks qualify but the Company chose to take the PTC for the Cross Winds Energy Park, Gratiot Wind Energy Park, and Crescent Wind Energy Park; the Company took the ITC (in the form of a cash grant under Section 1603 of ARRA) for the Lake Winds Energy Park in lieu of the PTC.

Q. Do the solar energy installations currently owned by the Company qualify for the ITC?

A. Yes, the Company has taken the ITC for the solar installations it owns at Grand Valley State University, Western Michigan University, and Circuit West.

Q. Under current law, will future solar energy parks either constructed or acquired by the Company qualify for the ITC?

A. Potentially, but not at the full ITC rate. Solar projects for which construction has started before January 1, 2020 will receive 100% of the ITC allowed under IRC 45 (i.e., the full 30% ITC). Solar projects for which construction starts on or after January 1, 2020 still qualify for the ITC but at a reduced rate. At the time the models supporting this IRP were run, solar projects that started construction on or after January 1, 2020 but before January 1, 2021 qualified for 26% ITC, solar projects that started construction on or after January 1, 2021 but before January 1, 2022 qualified for 22% ITC, and solar projects that started construction on or after January 1, 2022 only qualified for 10% ITC.

The Consolidated Appropriations Act of 2021 further extended the solar ITC. Solar projects that start construction on or after January 1, 2020 but before January 1, 2023 now qualify for 60% ITC while solar projects that start construction on or after January 1, 2023 but before January 1, 2024 qualify for 22% ITC. Solar projects that start construction before January 1, 2024 but that are not placed in service before December 31, 2025 only qualify for ITC of 10%, as do solar projects that start construction on or after January 1, 2024.

Q. When does the Company receive the benefit of the ITC?

A. The Company receives the benefit of the ITC in the year the energy property is placed in service.

Q. When do customers realize the benefit of the ITC?

A. The ITC is subject to normalization rules under the IRC. These rules require a public utility to pass the benefit of the ITC to customers ratably over the life of the asset.

SECTION III: ECONOMIC BENEFITS OF PTC/ITC

Q. For renewable energy projects that qualify for both the PTC and the ITC, how does the Company determine which to take?

A. The Company compares the amount of PTC or ITC expected to be generated by a particular project and generally chooses the tax incentive that produces the most tax benefit.

SECTION IV: FUTURE RISKS

Q. Is there any risk that Congress may enact legislation that substitutes the expiration dates for the PTC and/or the ITC described in this direct testimony for earlier dates?

A. Yes. Although it seems unlikely, there is a risk that Congress may decide to accelerate the PTC and/or ITC expiration dates. There are currently no bills proposed in Congress that would end PTC or ITC early, although the CEAA of 2019 would replace the current PTC and ITC with a new technology-neutral PTC and ITC. Both wind and solar would qualify for this new PTC and ITC. The current laws regarding PTC and ITC would remain in effect for projects placed in service before December 31, 2022. At this point, it looks more likely that the PTC and the ITC will be extended.

SECTION V: STORAGE

Q. Does energy storage property qualify for PTC or ITC?

A. Currently, there is no credit for “stand alone” energy storage property. Energy storage property charged by a wind or solar project that qualifies for the ITC will also qualify for ITC (even if added later). Although there is no language that explicitly prohibits storage from qualifying for the PTC, storage does not produce electricity so current thought is that there is no PTC for storage.

Q. Could this change?

A. Yes. President Biden's American Jobs Plan, the CEAA of 2019, and the GREEN Act of 2021 all include storage as a technology that would qualify for an ITC.

SECTION VI: TECHNOLOGY-NEUTRAL RENEWABLE TAX CREDITS

Q. What is meant by technology-neutral renewable tax credits?

A. The current PTC and ITC are available only for certain technologies enumerated in IRC 45 and IRC 48. A technology-neutral renewable tax credit would apply to any technology that generates "clean energy," however that might be defined by statute.

Q. Is there legislation currently proposed that would enact technology-neutral renewable tax credits?

A. The CEAA of 2019 proposes new IRC Section 45T and new IRC Section 48D. New IRC Section 45T provides for a new PTC that does not apply to specific technologies but instead applies to any qualified facility based on the carbon emissions of the qualified facility with zero-emission facilities qualifying for the maximum credit. The proposed new IRC Section 48D provides an ITC for the same facilities.

Q. Are there technologies the Company is considering that might qualify for technology-neutral renewable tax credits?

A. Under the CEAA of 2019, wind and solar, both zero-emission facilities, would qualify for the maximum credit. Energy storage property would qualify only for the new IRC Section 48D ITC. Carbon capture and sequestration equipment would qualify for both new credits. Other technologies currently under consideration, including hydrogen and renewable natural gas, should also qualify for these new credits.

SECTION VII: PROPERTY TAXES – PURCHASED NATURAL GAS PLANTS

Q. What amount of property taxes are projected for the purchased natural gas plants?

A. Exhibit A-75 (CK-1) provides a schedule showing the estimated property taxes for the New Covert Generating Facility for 2023 through 2040 and the Dearborn Industrial Generation, Livingston Generating Station, and Kalamazoo River Generating Station plants for 2025 through 2040.

SECTION VIII: CONCLUSION

Q. Does this conclude your direct testimony in this proceeding at this time?

A. Yes, it does.

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 Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))))	Case No. U-21090

DIRECT TESTIMONY

OF

BENJAMIN T. SCOTT

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

SECTION I: INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Benjamin T. Scott, 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 the Company?

A. I am a Senior Engineer Lead of High Voltage Distribution ("HVD") Planning West and Transmission within the Electric Grid Integration Department.

Q. Please describe your educational background.

A. I earned a Bachelor of Science degree in Electrical Engineering from the University of Michigan in 2010. I have been licensed as a Professional Engineer in the state of Michigan since 2015.

Q. Please describe your work experience with the Company.

A. I joined Consumers Energy in 2014 as an Engineer in HVD Planning. My duties included planning of the electric 46 kV and 138 kV distribution systems including 138/46 kV substations, industrial customer substations, and generator interconnections. I developed alternate solutions to correct projected capacity or low voltage system issues under the direction of a Senior Engineer Lead. From these alternate solutions, I identified economic alternatives, and developed those into project specifications to be engineered and constructed. In 2019, my responsibilities increased to include planning the development of Consumers Energy's electric transmission system, and ensuring adequate and reliable service, as measured by the North American Electric Reliability Corporation ("NERC")

Transmission Planning standards. My transmission planning responsibilities included: (i) development of plans for new or upgraded electric transmission lines and substations to maintain adequate voltage and maintain electrical loading within the capability of the equipment; (ii) identifying and planning new reactive supply additions required to maintain adequate voltage; (iii) planning new interconnections; and (iv) planning interconnection facilities associated with generation facilities. I was promoted to my present position in December 2020.

Q. What are your responsibilities as the Senior Engineer Lead of HVD Planning West and Transmission?

A. My responsibilities include oversight of engineers planning the development of approximately one-half of Consumers Energy's electric 46 kV and 138 kV distribution systems while still performing my previous job duties.

<u>SECTION II: PURPOSE OF TESTIMONY</u>

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to:

- Describe the Company's efforts to engage transmission owners during the development of the Company's Integrated Resource Plan ("IRP");
- Discuss transmission network upgrade and interconnection facilities cost assumptions utilized in the development of the Company's IRP;
- Discuss distribution network upgrade and interconnection facilities cost assumptions utilized in the development of the Company's IRP;
- Address capacity import and export limits utilized in the development of the Company's IRP; and
- Discuss transmission alternatives reviewed in the development of the Company's IRP.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-76 (BTS-1)	Notes of meetings between Michigan Electric Transmission Company and Consumers Energy;
Exhibit A-77 (BTS-2)	Michigan Electric Transmission Company's Transmission Evaluation for Consumers Energy's Integrated Resource Plan;
Exhibit A-78 (BTS-3)	MISO Michigan Capacity Import/Export Limit Expansion Study Report; and
Exhibit A-79 (BTS-4)	Planning Resource Auction (PRA) Results for Local Resource Zone 7.

Q. Were these exhibits prepared by you or under your direction?

A. Exhibits A-76 (BTS-1) and A-79 (BTS-4) were prepared by me or under my direction. Exhibit A-77 (BTS-2) is a transmission evaluation prepared for Consumers Energy by Michigan Electric Transmission Company, LLC ("METC"). This evaluation was prepared at the request of Consumers Energy for purposes of preparing and supporting the Company's IRP. Exhibit A-78 (BTS-3) is a capacity import capability evaluation for the state of Michigan prepared by the Midcontinent Independent System Operator, Inc. ("MISO"). This evaluation was prepared at the request of the Michigan Public Service Commission ("MPSC" or the "Commission").

SECTION III: TRANSMISSION OWNER ENGAGEMENT

Q. Did the Company engage local transmission owners in its IRP process?

A. Yes. The Company reached out to and established meetings with METC, a subsidiary of ITC Holdings Corporation ("ITC"), to discuss the IRP and request its analysis of future resource scenarios (as discussed below) and assessment of the associated effects on the transmission system. There are 311 interconnection points between the Company's electric distribution facilities and METC's electric transmission system making METC the predominant owner of electric transmission systems in the Company's retail service territory. METC operates high-voltage systems that transmit electricity from generating stations to local electricity distribution facilities in Michigan and surrounding areas. Through ITC's joint planning approach, these meetings also provided the perspectives of ITC Transmission ("ITCT"), also a subsidiary of ITC, which owns a fully-regulated high-voltage system that transmits electricity to local electricity distribution facilities in the eastern portion of the lower peninsula of Michigan. I participated in these meetings as a representative of the Company's transmission business.

Q. Did the Company engage any other transmission owners?

A. No. As part of its IRP, the Company does not anticipate interconnection of resources to systems other than those owned by METC and/or ITCT.

Q. How often did Consumers Energy and METC meet?

A. Consumers Energy and METC met seven times as part of the current IRP process. The meetings occurred on January 16, 2020, February 18, 2020, March 18, 2020, April 16, 2020, May 21, 2020, July 15, 2020, and August 25, 2020. Exhibit A-76 (BTS-1) contains mutually agreed upon meeting minutes to the extent that they were developed. The Company and METC also met informally on December 11, 2019, September 22, 2020, October 28, 2020, December 9, 2020, March 30, 2021, and April 29, 2021. Meeting minutes were not developed for informal meetings.

Q. What was the outcome of these discussions?

A. Various topics were discussed including IRP requirements and timelines, modeling assumptions, capacity import limits ("CILs"), and transmission alternatives. Ultimately, METC provided the Company with an IRP Transmission Evaluation as a result of these discussions. This IRP Transmission Evaluation sets forth the results of METC's evaluation of certain future scenarios and assessment of the effects on the transmission system. METC's analysis is provided in Exhibit A-77 (BTS-2).

SECTION IV: TRANSMISSION EVALUATION

Q. What scenarios were included in METC's IRP Transmission Evaluation?

A. METC provided an analysis of four different scenarios:

1. Generator additions and retirements in Planning Year[1] ("PY") 2031 based on the Company's 2018 Proposed Course of Action ("PCA") with updates as of November 2019 ("2018 PCA");
2. Retirement of J.H. Campbell ("Campbell") Units 1 and 2 by PY 2024 and by PY 2031;
3. Retirement of D. E. Karn ("Karn") Units 3 and 4 by PY 2024; and
4. Retirement of Campbell Units 1, 2, and 3, and Karn Units 3 and 4 by PY 2025.

Scenario 1: Generator Additions and Retirements in PY 2031 Based on 2018 PCA

Q. Please describe the 2018 PCA scenario METC studied.

A. This scenario included the retirement of 3,043 MW of existing generation and the addition of 4,900 MW of solar generation (3,430 MW connected to the transmission system and 1,470 MW connected to the distribution system) and 234 MW of wind generation in the METC footprint in PY 2031. METC performed a power flow analysis using the MISO Transmission Expansion Planning 2019 ("MTEP19") system model for year 2029 with all MISO published updates through January 2020 and the Company's provided load forecast. METC evaluated single point of failure outages for thermal and voltage violations to

[1] A PY runs from June 1 to the following May 31 as described by Company witness Thomas P. Clark.

determine the estimated transmission investment that would be necessary to accommodate the proposed scenario.

Q. Do you know why METC used the MTEP19 system model for 2029 as the basis of its evaluation?

A. MISO develops a series of transmission system models with different planning (time) horizons in each annual MTEP cycle. MISO develops powerflow system models for 2-year out, 5-year out, and 10-year out planning horizons. The MTEP19 system model for year 2029 represents the 10-year out planning horizon and is the closest planning horizon to PY 2031.

Q. Do you agree with the use of the MTEP19 system model for 2029 as the basis of METC's evaluation?

A. Yes.

Q. How were generator additions sited in the models?

A. The Company provided siting assumptions for generation additions to METC. The siting assumptions were divided into three categories:

1. "584 MW Solar – Public Utility Regulatory Policies Act of 1978 Contracts"

   This category was assumed to be 100% connected to the distribution system. The Company provided specific bus, or substation, locations in the MISO MTEP19 system models for this category;

2. "Remaining PCA Solar Generation"

   This category was assumed to be 30% connected to the distribution system and 70% to the transmission system for years 2022 through 2031. The Company provided specific bus locations in the MISO MTEP19 models for the distribution-connected solar generation. The Company provided two different scenarios for siting the transmission-connected solar generation. In Scenario #1, siting was informed from the MISO Generator Interconnection Queue as of February 2020. Scenario #2 was similar to Scenario #1 except that the Company included four Company-selected sites.

3. "234 MW REP-IRP Wind (Remaining Wind Generation yet to be contracted)"

   This category was assumed to be connected to the transmission system and provided by wind projects from the MISO Definitive Planning Phase April 2018 Cycle.

Q. What levels of investment did METC identify for the scenario studied?

A. METC determined that the minimum cost of transmission network upgrades for the 2018 PCA scenario was $530 million, or $144 per kilowatt ($/kW) on a per unit basis. See Exhibit A-77 (BTS-2).

Q. Is the required level of investment projected in METC's Transmission Evaluation of the 2018 PCA scenario studied reasonable?

A. While METC's results are based on several assumptions that make those results subject to change, the results of the METC Transmission Evaluation are reasonable and representative of the level of investment projected for the 2018 PCA scenario based on the summary provided by METC in its Transmission Evaluation.

Q. Why are the results subject to change or otherwise uncertain?

A. The MTEP19 system model for year 2029 used by METC represents a "snapshot" in time of system topology, load forecasts, and generation. In each annual MISO MTEP cycle between the time that the MTEP19 system models were developed and 2029, load forecasts will be updated, generation resources will be added and retired, and new transmission system improvement projects will be approved. Thus, it is likely that the configuration of the transmission system in 2029 will be different than how it is represented in the system model used by METC in its Transmission Evaluation. Again, however, even with the uncertainty of modeling the transmission system 10 years in the future, the Company maintains that the METC Transmission Evaluation is still meaningful, reasonable, and representative of the level of investment projected for the 2018 PCA scenario.

Q. Does METC acknowledge the limitations of its Transmission Evaluation?

A. Yes. In its Transmission Evaluation, METC states that "METC made certain estimates and assumptions that may differ from actual numbers and scenarios." The system needs identified and the associated costs will vary depending on actual generator additions, retirements, and the corresponding power flows. The Transmission Evaluation report goes on to say that its "analysis was scoped as a high-level evaluation based on available data and assumptions at the time of the study. It should not be treated as a representation of or equivalent to an attachment Y1 study as performed by MISO due to various factors such as, but not limited to, modeling data, study process, and remedial actions."

Q. Does the 2018 PCA scenario align with the set of possible scenarios utilized by the Company to arrive at the Company's PCA?

A. Yes. The 2018 PCA scenario studied by METC and the possible scenarios utilized by the Company contemplate similar amounts of new solar generation resource additions through PY 2031 as described by Company witness Richard T. Blumenstock.

Q. What is the value of METC's study results given that the scenario studied aligns with the Company's IRP scenarios?

A. METC's results are informative. The scenario studied by METC provides insight into the potential impacts of generation unit retirements, coupled with the addition of generation across the Company's service territory. These results demonstrate that transmission network upgrades are likely necessary on the Lower Michigan transmission network to accommodate a changing generation fleet and demonstrate the level of investment that may be necessary.

Scenario 2: Impacts to Transmission System for Retirement of Campbell Units 1 and 2 by PY 2024 and by PY 2031

Q. Please describe the Campbell Units 1 and 2 retirement scenario that the Company requested METC to study.

A. The Company requested METC to perform an analysis of impacts to the transmission system for the retirement of Campbell Unit 1, Campbell Unit 2, and Campbell Units 1 and 2 together for potential retirement dates of 2024, 2025, 2026, 2028, and 2031.

Q. What analysis did METC provide for the Campbell Units 1 and 2 retirement scenarios?

A. METC provided an analysis of the retirement of Campbell Unit 1, Campbell Unit 2, and Campbell Units 1 and 2 together by PY 2024 and by PY 2031.

Q. Why did METC only study years 2024 and 2031?

A. According to METC's Transmission Evaluation report, it was unnecessary to perform the same analysis for the intermediate years due to minimal difference in system upgrades needed in the bookend models.

Q. Do you agree with METC's assessment that intermediate years do not need to be studied for the retirement of Campbell Units 1 and 2?

A. Yes.

Q. What were the results of METC's study of the impacts to the transmission system due to the retirement of Campbell Units 1 and 2?

A. According to METC's Transmission Evaluation report, steady state results showed local system concerns that require transmission network upgrades after Campbell Units 1 and 2 are retired. The transmission network upgrades include a 345/138 kV transformer and overhead line upgrades.

Q. What levels of investment did METC identify for the transmission network upgrades associated with the Campbell Unit retirements?

A. METC determined that the preliminary cost estimate of transmission network upgrades associated with the retirement of Campbell Units 1 and 2 is $20 million. METC also provided the equivalent revenue requirement associated with the retirement of Campbell Units 1 and 2. See testimony of Company witness Sara T. Walz for a description of how the revenue requirement was used in the Company's IRP modeling.

Q. Is the required level of investment projected by METC under Scenario 2 reasonable?

A. Yes. For the same reasons discussed above under Scenario 1, the preliminary cost estimate provided by METC is reasonable.

Scenario 3: Impacts to Transmission System for Retirement of Karn Units 3 and 4 by PY 2024

Q. Please describe the Karn Units 3 and 4 retirement scenario the Company requested METC to study.

A. The Company requested METC to perform an analysis of impacts to the transmission system for the retirement of Karn Units 3 and 4 for a potential retirement date in PY 2025.

Q. What analysis did METC provide for the Karn Units 3 and 4 retirement scenario?

A. METC provided an analysis of the retirement of Karn Units 3 and 4 in PY 2024.

Q. Why did METC study year 2024 instead of 2025?

A. At the time of the Company's request, METC had developed the 2024 system model for Scenario 2. METC indicated that there would be minimal differences in the system models between 2024 and 2025. Based on METC's guidance, the Company agreed to METC studying the retirement of Karn Units 3 and 4 in PY 2024.

Q. What were the results of METC's study?

A. According to METC's Transmission Evaluation report, steady state results identified some transmission issues that required transmission network upgrades as a result of these retirements. METC determined that the preliminary cost estimate of transmission network upgrades associated with this scenario is $12.4 million. METC also provided the equivalent revenue requirement associated with this scenario. See the testimony of Company witness Walz for a description of how the revenue requirement was used in the Company's IRP modeling.

Q. Is the required level of investment projected by METC under Scenario 3 reasonable?

A. Yes. For the same reasons discussed above under Scenario 1, the preliminary cost estimate provided by METC is reasonable.

Scenario 4: Impacts to Transmission System for Retirement of Campbell Units 1, 2, and 3 and Karn Units 3 and 4 by PY 2025

Q. Please describe the final retirement scenario the Company requested METC to study.

A. The Company requested METC to perform an analysis of impacts to the transmission system for the potential retirement of Karn Units 3 and 4 by PY 2023 and Campbell Units 1, 2, and 3 by PY 2025.

Q. What analysis did METC provide for this retirement scenario?

A. METC provided an analysis of the retirement of Karn Units 3 and 4 and Campbell Units 1, 2, and 3 in PY 2025.

Q. Why did METC study all five units retiring in 2025 instead of the scenario requested by the Company?

A. METC indicated that it preferred to study all five units retiring in the same year. There were more significant generation retirements and additions in 2025 so it was chosen as the more interesting year to study. Based on METC's guidance, the Company agreed to METC studying the retirement of all five units in PY 2025.

Q. What were the results of METC's study?

A. According to METC's report, steady state results identified 11 system issues that require transmission network upgrades as a result of these retirements. Three of the transmission network upgrades have been submitted in the MTEP21 cycle[2] for other reasons. METC determined that the preliminary cost estimate of transmission network upgrades associated with this scenario is $82.1 million, excluding the MTEP21-submitted projects, and $97.2 million including the MTEP21-submitted projects. METC also provided the equivalent revenue requirement associated with this scenario. See testimony of Company witness Walz for a description of how the revenue requirement was used in the Company's IRP modeling.

Q. Is the required level of investment projected by METC under Scenario 4 reasonable?

A. Yes. For the same reasons discussed above under Scenario 1, the preliminary cost estimate provided by METC is reasonable.

SECTION V: TRANSMISSION NETWORK UPGRADES AND INTERCONNECTION COSTS

Q. What are network upgrades?

A. Network upgrades are additions, modifications, and upgrades to the existing utility system, whether that system is transmission or distribution, to accommodate the interconnection of a new generation resource to the utility system. They are located at or beyond the point where the interconnection facilities connect to the utility system. Examples of network

[2] MISO designates each MTEP cycle by using the year during which it is under consideration. During this cycle, METC submits project proposals for MISO to review and approve. MTEP21 is the present and ongoing 2021 study cycle or process; thus, MISO is currently considering these projects for approval.

upgrades include, but are not limited to, a new switching station, protection system upgrades, and existing electric line rebuilds.

Q. What transmission network upgrade cost assumption was used in the Company's IRP analysis?

A. A transmission network upgrade cost assumption of $46,000 per megawatt ($/MW), equivalent to $46/kW of generation capacity, was used for all generation technologies located in Michigan. The transmission network upgrade cost assumption was included as an input assumption for new transmission-connected generation resources offered for selection in the production cost model as described by Company witness Walz.

Q. How was the Company's transmission network upgrade cost assumption determined?

A. The network upgrade cost assumption was determined from a survey of 11 Generator Interconnection Agreements ("GIA") executed between 2017 and 2019 with either METC or ITCT, as reported in the generation interconnection queue on the MISO website[3]. The data was obtained from the executed GIAs posted in the Federal Energy Regulatory Commission's ("FERC") eDocket[4] system. Network upgrade costs across these 11 GIAs[5] ranged from $5.30/kW to $172.30/kW. The weighted average of these network upgrade costs was $46/kW.

[3] https://www.misoenergy.org/planning/generator-interconnection/GI_Queue/
[4] https://elibrary.ferc.gov/IDMWS/docket_search.asp
[5] The 11 GIA's reviewed are contained within FERC Docket Nos.: ER17-2250, ER17-2273, ER18-2340, ER19-311, ER19-415, ER19-2457, ER20-46, ER20-81, ER20-196, ER20-1774, and ER20-3044.

Q. Were transmission network upgrade costs provided in METC's analysis?

A. Yes, METC's Transmission Evaluation determined transmission network upgrade costs to be $144/kW on a per unit basis in Scenario 1.

Q. Describe the differences between the Company's transmission network upgrade assumption and METC's analysis?

A. The Company's method is based on a weighted average of actual historical interconnection costs in GIAs executed from 2017 to 2019. As stated above, the system model used by METC represents a future snapshot in time using assumptions regarding system topology, load forecasts, and generation siting.

Q. Did the Company utilize METC's transmission network upgrade costs in its IRP analysis?

A. Yes. The Company conducted a sensitivity analysis of the transmission network upgrade costs, increasing them from the Company's $46/kW assumption to METC's $144/kW assumption. The method and resulting outcome of this analysis are detailed by Company witness Walz.

Q. The Company's analysis and METC's analysis provide a range of transmission network upgrade costs; can you determine a definitive cost associated with the Company's PCA?

A. No. Network upgrade costs vary by project. Installed generation capacity (MW), connection voltage, and location on the transmission grid are among the variables that influence network upgrade costs. Network upgrade costs for a specific transmission-connected project can only be determined through a MISO generator interconnection study for new generation, or a MISO generator retirement (Attachment Y) study for retiring generation units.

Q. What are interconnection facilities?

A. Interconnection facilities are facilities required to physically and electrically connect the generation resource to a utility system whether that system is transmission or distribution. They are located between the generating facility and the point of interconnection to the utility system. Examples of interconnection facilities include, but are not limited to, a generation tie line, disconnect switches, and substation line exit structure.

Q. What transmission interconnection facilities cost assumption was used in the IRP?

A. A transmission interconnection facilities cost assumption of $2,000/MW, equivalent to $2/kW of generation capacity, was used for all generation technologies located in Michigan. The transmission interconnection facilities cost assumption was included as an input assumption for new transmission-connected generation resources offered for selection in the production cost model as described by Company witness Walz.

Q. How was the transmission interconnection facilities cost assumption determined?

A. The interconnection facilities cost assumption was determined using a survey of the same 11 GIAs used to determine the transmission network upgrades cost assumption. Interconnection facilities costs across these 11 GIAs ranged from $0.60/kW to $4.90/kW. The weighted average of these interconnection facilities costs was $2.00/kW.

Q. Were transmission interconnection facilities costs provided in METC's analysis?

A. No. METC's Transmission Evaluation did not provide a discrete value for interconnection facilities costs.

SECTION VI: DISTRIBUTION NETWORK UPGRADES AND INTERCONNECTION COSTS

Q. What distribution network upgrade cost assumption was used in the IRP?

A. A distribution network upgrade cost assumption of $24,000/MW, equivalent to $24/kW, of generation capacity was used for all generation technologies located in Michigan. The distribution network upgrade cost assumption was included as an input assumption for new distribution-connected generation resources offered for selection in the production cost model as described by Company Witness Walz.

Q. How was the distribution network upgrade cost assumption determined?

A. The network upgrade cost assumption was determined from a survey of eight Facilities Agreements ("FAs") and Generator Interconnection Operating Agreements ("GIOAs") executed with the Company from 2019 to 2020. Network upgrade costs across these eight FAs and GIOAs ranged from $0/kW to $33.30/kW. The weighted average of these network upgrade costs was $24/kW.

Q. What distribution interconnection facilities cost assumption was used in the IRP?

A. A distribution interconnection facilities cost assumption of $60,000/MW, equivalent to $60/kW, of generation capacity was used for all generation technologies located in Michigan. The distribution interconnection facilities cost assumption was included as an input assumption for new distribution-connected generation resources offered for selection in the production cost model as described by Company witness Walz.

Q. How was the distribution interconnection facilities cost assumption determined?

A. The interconnection facilities cost assumption was determined using a survey of the same eight FAs and GIOAs used to determine the distribution network upgrades cost assumption. Interconnection facilities costs across these eight FAs and GIOAs ranged from $10.00/kW to $133.50/kW. The weighted average of these network upgrade costs was $60/kW.

Q. Did METC provide distribution network upgrade or interconnection facility costs?

A. No. METC, as a transmission owner, had no experience or data to share regarding distribution interconnections.

<u>SECTION VII: CAPACITY IMPORT AND EXPORT LIMITS</u>

Q. What is a CIL?

A. The CIL is a value calculated by MISO that represents the transmission system's ability to reliably import or transfer power into a Local Resource Zone ("LRZ") from other MISO LRZs under specified system conditions. MISO determines the CIL for each LRZ by evaluating single-element contingencies in a summer peak powerflow study model.

Q. What is a Capacity Export Limit ("CEL") and what is the significance of CEL?

A. The CEL is a value calculated by MISO that represents the transmission system's ability to export or transfer power from a LRZ to other MISO LRZs under certain system conditions. MISO determines the CEL for each LRZ by evaluating single-element contingencies in a summer peak powerflow study model.

Q. What CIL and CEL assumptions were made in the preparation of the Company's IRP?

A. The Company utilized a CIL of 3,200 MW and no limit for CEL in its IRP modeling data assumptions and Capacity Sufficiency Analysis ("CSA")[6]. Company witness Walz describes the use of CIL in IRP modeling and the CSA in further detail.

Q. How did the Company determine the CIL and CEL values for its IRP modeling data assumptions and CSA?

A. The Company utilized the most recent public reports from MISO available at the start of the IRP modeling process. MISO analyzed the transmission import and export capabilities for the MISO LRZ7, which essentially encompasses the entire geographic area of the Lower Peninsula of Michigan. The result of the analysis is contained within the PY 2020/2021 Loss of Load Expectation ("LOLE") Study Report ("PY 20/21 LOLE Report") available on the MISO website[7]. The PY 20/21 LOLE Report provides CIL and CEL data for the 2020/2021 PY. MISO determined the CIL and CEL for LRZ7 to be 3,200 MW and no limit, respectively. The CIL was constrained by voltage issues at the Praxair 120 kV bus (substation) in MISO's study, and no constraint for the CEL was identified because LRZ7 runs out of dispatchable generation to export before a transmission constraint is reached.

Q. Is this the most recent information published by MISO on CIL and CEL?

A. No. Since the start of the IRP modeling process, MISO published updated CIL and CEL values in the PY 2021/2022 LOLE Report ("PY 21/22 LOLE Report") available on the

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[6] See Company witness Walz for a description of the differences and similarities between the Company's CSA and a LOLE analysis performed by MISO.
[7] https://cdn.misoenergy.org/2020%20LOLE%20Study%20Report397064.pdf

MISO website[8]. In its updated PY 21/22 LOLE Report, MISO determined the CIL and CEL for LRZ7 to be 4,888 MW and no limit, respectively. The CIL was constrained by thermal limits being reached on the Palisades to Argenta 345 kV #2 branch in MISO's study, and no constraint for the CEL was identified because LRZ7 runs out of dispatchable generation to export before a transmission constraint is reached.

Q. Have any studies been performed to estimate LRZ7 CIL and CEL values outside of the annual MISO LOLE report process?

A. Yes. MISO performed the Michigan CIL/CEL Expansion Study at the request of MPSC Staff. I participated in the study as a representative of the Company. METC also participated in the study as a stakeholder. See Exhibit A-78 (BTS-3).

Q. What was the purpose of this study?

A. The purpose of the study was to investigate options to increase the CIL and CEL for MISO's LRZ7. The study primarily focused on the CIL as the CIL is the more limiting constraint for LRZ7.

Q. What scenarios did the study consider?

A. The study considered three different scenarios. In each scenario, MISO's study investigated opportunities to increase the LRZ7 CIL. Scenario 1 was a five-year outlook (Year 2024) with an objective to increase CIL from 3,200 MW to 4,700 MW. Scenario 2 was a 12-year outlook (Year 2032) with an objective to increase CIL from 3,200 MW to 6,200 MW. Scenario 2 included generation addition and retirement assumptions from the Company's 2018 IRP including the retirement of Karn Units 1 and 2 in 2023 and Campbell Units 1 and 2 in 2031. Scenario 3 was a 15-year outlook (Year 2035) with an objective to

[8] https://cdn.misoenergy.org/PY%202021%2022%20LOLE%20Study%20Report489442.pdf

increase CIL from 3,200 MW to 6,200 MW. Scenario 3 included the same generation retirement assumptions as Scenario 2 but doubled the Scenario 2 generation addition assumptions.

Q. How do MISO's study assumptions compare to the Company's PCA?

A. MISO's study contemplates higher renewable penetration than the Company's PCA in the 12-year and 15-year time horizons. The Company's PCA calls for a total 4,810 MW of solar and 61 MW of storage resources in 2032 and 5,302 MW of solar and 145 MW of storage resources in 2035. Scenario 2 assumed the Company would have 6,168.5 MW of solar and 50 MW of storage resources in 2032 and 6,618.5 MW of solar and 200 MW of storage resources in 2035. Scenario 3 assumed the Company would have 12,333.7 MW of solar and 50 MW of storage resources in 2032 and 13,233.7 MW of solar and 200 MW of storage resources in 2035. It should be noted that for the Company to develop the levels of solar in Scenario 3 from 2025 to 2032, it would need to consistently develop approximately 1,600 MW of solar per year. As described by Company witness Jeffrey E. Battaglia, the Company assumes development of 500 MW per year of solar as feasible to achieve.

Q. What were the outcomes of the study?

A. In each scenario, the CIL prior to transmission project additions was demonstrated to remain above 3,200 MW. The initial CIL obtained for Scenario 1 was 5,278 MW. This exceeded the Scenario 1 objective to increase CIL to 4,700 MW. As such, no additional alternative projects were required to meet the Scenario 1 objective. The initial CIL obtained for Scenario 2 was 4,097 MW. Alternative projects were required to meet the Scenario 2 objective to increase CIL to 6,200 MW. Seven alternative projects proposed by various stakeholders were able to resolve the Scenario 2 constraint. The initial CIL obtained for Scenario 3 was 5,513 MW. Alternative projects were required to meet the Scenario 3 objective to increase CIL to 6,200 MW. Five alternative projects proposed were able to resolve the Scenario 3 constraint. Overall, two projects, one proposed by ITC/METC and one proposed by DTE, were able to resolve both the Scenario 2 and Scenario 3 constraints.

Q. Did MISO note any limitations to the study methodology?

A. Yes, MISO noted three primary limitations to the analysis performed. First, various assumptions, including siting of new generator additions, were made in developing the study models. The constraints and associated upgrades were demonstrated to be sensitive to the siting assumptions and that changing the siting assumptions of new generators could mitigate identified transmission system constraints and reduce or eliminate the need for certain transmission system upgrades to achieve the higher import limits. Second, the study focused on dispatch and import capability only during system peak conditions (a single point in time). Import capabilities could be different during other times of the year. MISO's Reliability Imperative initiative and its Marked Redefinition and Long Range Transmission Planning workstreams will consider a broader set of risks and challenges to maintain and increase the reliability of the MISO grid including LRZ7. Third, additional reliability studies, such as system impact studies, would need to be performed to confirm the estimated project costs and that the proposed projects meet all applicable planning criteria.

Q. MISO's study provided possible solutions to increase the CIL; how should these solutions be viewed?

A. Because of the limitations stated above, MISO's study should be viewed as informational only. MISO's study results can inform future planning decisions should an increase in CIL be required. They provide insight into the potential impacts of generation unit retirement, coupled with the addition of generation across LRZ7 under certain scenarios over a 15-year time horizon. These results demonstrate that certain transmission network upgrades could potentially increase CIL. MISO's study results, however, do not definitively demonstrate that increasing CIL is required or economically justified at this time.

Q. What conditions would require the CIL for LRZ7 to be increased?

A. An increase in the CIL may be required if the LRZ7 Local Clearing Requirement ("LCR")[9] exceeds the LRZ7 Planning Reserve Margin Requirement ("PRMR")[10] or, in cases where the LCR is less than the PRMR, there is a need or desire to import supply resources external to LRZ7 for the purposes of meeting the PRMR in excess of the existing LRZ7 CIL. By subtracting the LCR from the PRMR, the maximum amount of resources external to LRZ7 that could be used to meet the PRMR can be determined.

Q. What do the results of the recent MISO Planning Resource Auction ("PRA") indicate as far as availability of CIL?

A. The PRA results for PY 2021/2022[11] show the LRZ7 PRMR to be 21,459.2 MW and the LRZ7 LCR to be 19,710.1 MW. Subtracting the LCR from the PRMR results in 1,749 MW

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[9] LCR is the minimum amount of supply resources that must be physically located within an LRZ in order to meet the 1 day in 10-year LOLE standard. As discussed by Company witness Clark, it is calculated by subtracting CIL and non-pseudo tied exports from the Local Reliability Requirement.
[10] PRMR is forecasted peak demand (coincident with MISO's peak demand) plus a reserve margin. It is effectively the capacity requirement to adequately serve customer demand.
[11] PY 21/22 PRA Results: https://cdn.misoenergy.org/PY21-22%20Planning%20Resource%20Auction%20Results541166.pdf, page7

of external resources could be used to meet the PRMR. This is well below the LRZ7 CIL of 4,888 MW. This indicates that there is still 3,139 MW of unused import capability. See Exhibit A-79 (BTS-4).

Q. What do the results of previous MISO PRAs indicate as far as availability of CIL?

A. PRAs for the previous seven planning years – PY 2014/2015 through PY 2020/2021 – demonstrate that the amount of resources external to LRZ7 that could be used to meet the PRMR has been less than the existing LRZ7 CIL. The amount of CIL that could be utilized in these planning years was 1,705 MW; 1,236 MW; 1,555 MW; 1,186 MW; 1,493 MW; 164 MW; and 95 MW, respectively[12]. See Exhibit A-79 (BTS-4).

Q. What percentage of the LRZ7 CIL was unutilized in the PRA results for PY 2014/2015 through PY 2021/2022?

A. On a percentage basis, the amount of CIL unutilized for these eight years was 56%, 68%, 56%, 64%, 61%, 95%, 97%, and 64%, respectively. This results in an average unutilized rate of approximately 70% over the eight-year period.

Q. Does the LCR exceed the PRMR in the PRA results for PY 2014/2015 through PY 2021/2022?

A. No.

[12] PY 2014/2015 PRA Results: https://cdn.misoenergy.org/2014-2015%20PRA%20Results89073.pdf, page 2; PY 2015/2016 PRA Results: https://cdn.misoenergy.org/2015-2016%20PRA%20Results87078.pdf, page 6; PY 2016/2017 PRA Results: https://cdn.misoenergy.org/2016-2017%20PRA%20Results87167.pdf, page 8; PY 2017/2018 PRA Results: https://cdn.misoenergy.org/2017-2018%20Planning%20Resource%20Adequacy%20Results87196.pdf, page 9; PY 2018/2019 PRA Results: https://cdn.misoenergy.org/2018-19%20PRA%20Results173180.pdf, page 10; PY 2019/2020 PRA Results: https://cdn.misoenergy.org/20190412_PRA_Results_Posting336165.pdf, page 7; PY 2020/2021 PRA Results: https://cdn.misoenergy.org/2020-2021%20PRA%20Results442333.pdf, page 7

Q. Are solutions to increase the CIL needed or economically justified?

A. No. As demonstrated in the recent MISO PRAs, and noted above, the LCR does not exceed the PRMR and there is an abundance of CIL that is not being utilized to meet the LRZ7 PRMR meaning that capacity and resource adequacy requirements can be met without increasing the CIL. The capital costs to build transmission solutions to increase the CIL would most likely be included in the rates METC and ITCT charge for transmission service. If CIL increases are not needed to meet the capacity and resource adequacy requirements for LRZ7, transmission system investment costs to increase CIL would derive no benefits to ratepayers but would increase customer rates.

Additionally, there is no justification to approve the transmission solutions contemplated in the Michigan CIL/CEL Expansion Study through the MTEP because the transmission solutions cannot demonstrate a need to increase the CIL based on NERC Transmission Planning Standards, local transmission planning criteria, and/or other state requirements.

Q. Will increasing CIL provide a supply source the Company could use to satisfy resource adequacy requirements?

A. No. The transmission system provides the path to move remote supply sources into a zone, which is limited by CIL; however, those remote supply sources do not necessarily exist. Even if the Company did contract with external resources, these resources do not provide a complete supply option because external resources can only be counted toward meeting the PRMR and not the LCR.

Additionally, potential increases to the LRZ7 Local Reliability Requirement would offset increases to CIL. As a result, the LRZ7 LCR may not decrease.

Q. Are increases in CIL necessary to support the Company's IRP?

A. No. MISO's PY 21/22 LOLE Report and Michigan CIL/CEL Expansion Study, both published after the initiation of the Company's IRP modeling, indicate LRZ7 CIL values will remain above 3,200 MW. As discussed by Company witnesses Clark and Walz, the Company's PCA is structured to meet its capacity requirements with in-zone resources. As discussed by Company witness Walz, the Company's CSA analysis demonstrates that the Company's PCA can meet its resource adequacy requirements at the modeled CIL level of 3,200 MW.

SECTION VIII: TRANSMISSION ALTERNATIVES

Q. Is utilization of transmission import capacity an alternative to supply-side resources?

A. No. As discussed above, remote sources of capacity are required to leverage the import capacity provided by the transmission system.

Q. Did METC provide any information on potential transmission options that could increase import or export capability?

A. No. In the Company's meetings with METC, they indicated that increasing the import capability could be a transmission alternative, but METC did not provide any specific options directly to the Company. METC did, however, participate in MISO's Michigan CIL/CEL Expansion Study as a stakeholder.

Q. Did METC provide any information on potential transmission options that could facilitate power purchase agreements or sales of energy and capacity both within or outside the planning zone or from neighboring Regional Transmission Organizations?

A. No, not that I am aware of.

Q. Did METC provide any information on transmission upgrades resulting in increased system efficiency and reducing line loss?

A. No. Although METC projects presently approved through the MTEP process may incidentally increase system efficiency and reduce line losses in some small measure, METC did not offer any upgrades specifically for this purpose.

Q. Are you aware of any transmission projects planned or approved solely to reduce losses or improve system efficiency in Lower Michigan?

A. No. While the completion of transmission projects can reduce system losses, I am unaware of any planned projects that have been proposed solely for this purpose.

Q. Did METC provide any information on advanced transmission network technologies that could affect supply-side or demand-side resources?

A. No.

Q. Does this conclude your direct testimony?

A. Yes.

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 Approval of an Integrated Resource Plan	)	Case No. U-21090
under MCL 460.6t, certain accounting	)	
approvals, and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

TERI L. VANSUMEREN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

Q. Please state your name and business address

A. My name is Teri L. VanSumeren, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Executive Director of Energy Waste Reduction ("EWR").

Q. Please describe your education and professional experience.

A. I earned a bachelor's degree in engineering science from Michigan State University. In 1983, I accepted the position of Graduate Load Research Analyst in the Marketing Research and Pricing Department with Consumers Power Company (later Consumers Energy). In 1990, I was promoted to Supervisor of Load Monitoring and Analysis in the Research and Rate Administration Department, which included supervising the Company's load research. In 1991, I was promoted to Energy Research and Evaluation Supervisor in the Customer Program Services Department, which included supervising the evaluation of the Company's Demand-Side Management and Energy Conservation programs. In 1997, I was promoted to Director of Customer Research in which I was responsible for the Company's residential and business customer marketing research. In 2009, I was asked to oversee the Company's Energy Optimization ("EO") Plan as Manager of Energy Efficiency Solutions. In 2016, I was promoted to my current position as Director of EWR.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I have sponsored testimony in the following Commission cases:

U-10544 Demand-Side Management Reconciliation case;

U-10755	System-Wide Gas Load Study;
U-15290	Approval of Consumers Energy's Balanced Energy Initiative and Other Relief;
U-16566	Reconciliation of the Electric Pilot Revenue Decoupling Mechanism;
U-16736	2011 EO Plan Reconciliation;
U-16988	Reconciliation of the Electric Pilot Revenue Decoupling Mechanism;
U-17138	2012 – 2015 Biennial EO Plan;
U-17351	2014 – 2017 Biennial EO Plan;
U-17429	Certification of Necessity for the Thetford Generating Plant;
U-17771	2016 – 2017 Biennial EO Plan;
U-18231	2017 Renewable Energy Plan;
U-18250	Palisades Securitization; and
U-18351	Voluntary Green Pricing Programs.

Q. What is the purpose of your direct testimony in this case?

A. The purpose of my direct testimony is to describe the benefits and necessity of the Company's investment in customer programs that promote EWR, Demand Response ("DR"), Voluntary Green Pricing ("VGP"), and Electric Vehicle ("EV") market development. In addition, I will discuss the opportunity to include Conservation Voltage Reduction ("CVR") energy savings in the Company's EWR Program.

Q. Are you sponsoring any exhibits in this case?

A. No.

Q. Please describe the Company's commitment to its Clean Energy Plan and the customer programs that are necessary to achieve the plan.

A. Consumers Energy has provided reliable, affordable electricity and natural gas to advance its customers' quality of life for more than 130 years. Consumers Energy remains committed to planning for and ensuring an adequate electricity and natural gas supply to meet the needs of Michigan homes and businesses, now and in the future. More than just supplying energy, however, Consumers Energy remains a vital part of the state's economic, social, and environmental network, committed to the customers and communities it serves. In 2019, Consumers Energy began a transformative journey with the approval of its Integrated Resource Plan ("IRP") in Case No. U-20165, which the Company describes as the Clean Energy Plan. Consumers Energy's Clean Energy Plan set a course for the Company to meet customers' long-term energy needs as a lean and green utility committed to a triple bottom line of people, planet, and prosperity. In the Clean Energy Plan, demand reduction, including EWR and DR, takes on a critical role in meeting the Company's residential and business customers' energy and capacity needs. The VGP Program allows the Company to support customers' clean energy goals while increasing the amount of renewable energy in the state. The Company's work to expand the EV market, while limiting the impact of charging infrastructure on load growth, plays a critical role in advancing the adoption of EVs in the state of Michigan. Overall, the Company's customer programs play a critical role supporting the Company's Clean Energy Plan.

Q. Please describe the Company's EWR Program and how it aligns with the Clean Energy Plan.

A. Since 2009, Consumers Energy has been implementing a diverse and balanced portfolio of EWR programs that have achieved significant energy savings for all major sectors and customer classes, including small businesses and low-income customers. EWR programs have delivered significant economic, social, and environmental benefits to Michigan, including:[1]

- Delivering EWR savings equivalent to supplying electricity to 23,000 residential homes and natural gas to 14,000 residential homes for a year;
- Garnering participation in at least one EWR program from more than 795,000 residential and 101,000 business customers;
- Saving customers over $3.9 billion on their energy bills;
- Creating or saving more than 7,700 Michigan jobs;
- Adding $3.35 billion in net growth to the Michigan economy;
- Increasing personal income by almost $1.60 billion;
- Helping over 150,000 low income customers make their homes and apartments more energy efficient and affordable; and
- Preventing the emission of over 8.8 million tons of carbon dioxide.

As shown by 10 years of success, the EWR Program is an integral part of the Company's Clean Energy Plan and triple bottom line, and is good for Michigan. The Company believes everyone has the power to save and should have the opportunity to participate in EWR (people); EWR helps lower greenhouse gas emissions and protect natural resources (planet); and improving efficiency in homes and businesses is clean, smart, relatively

[1] See the Company's 2020 EWR Reconciliation in Case No. U-20865, available at https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000Ooc44AAB.

inexpensive, and serves to help stabilize volatile energy prices and boost energy security (prosperity). As such, Consumers Energy is strongly committed to helping customers get the most value possible for every kWh of electricity or cubic foot of natural gas through the comprehensive portfolio of EWR programs and opportunities for all customers.

Q. How is the EWR Program included in the IRP proposed in this case?

A. As described by Company witness Steven Q. McLean, the Company created an EWR prototype that includes the maximum achievable cumulative energy savings ("cumulative savings"), incremental annual energy savings ("incremental savings"), and associated costs for the 2021 through 2040 timeframe. The cumulative and incremental savings and associated costs were developed based on the Company's past experience implementing EWR programs, the results of the Company's previous IRP approved in Case No. U-20165, and the Consumers Energy 2021 EWR Potential Study ("2021 EWR Potential Study") supported by Company witness Lakin Garth. The cumulative savings and associated costs are included in the IRP modeling for the Company's Proposed Course of Action ("PCA"), lowering the overall load forecast. As supported by Company witnesses McLean and Garth, the incremental savings represent the annual program savings that will be targeted in future EWR plan filings. While the incremental savings fluctuate over time, the average annual savings for 2021 through 2040 is 1.9%, which is slightly below the incremental savings included in the Case No. U-20165 IRP.

Q. Will the Company continue to pursue 2.0% annual savings as part of the EWR Program?

A The Company will continue to pursue 2.0% savings in the biennial EWR plan filings so long as it is achievable and cost effective. The EWR planning and reconciliation process allows the opportunity to review EWR potential and costs on an ongoing basis.

Q. What is CVR?

A. Company witness Matthew S. Henry describes the Company's CVR Program, overall performance, and supports the impact and associated costs on the Company's PCA. Company witness Henry notes that the primary objective of CVR is to reduce energy demand and the associated carbon footprint of the electric system by optimizing service-point voltages without requiring active participation or behind the meter investment by customers.

Q. Does CVR share any similarity to EWR?

A. Yes. While CVR does not require customer participation like most EWR programs, it does provide energy savings similar to those achieved through EWR programs. As described by Company witness Henry, one of the objectives for CVR is to serve an EWR goal by lowering energy usage year-round through voltage and load reduction. This every day, year-round voltage reduction reduces end-load usage throughout every season, at all hours of the day. The CVR Program also provides demand reduction benefits by reducing peak system load for a few hours at a time during the summer cooling season. The similarities between EWR and CVR were also discussed in the Commission's December 17, 2020 Order in Case. U-20697.

Q. Is the Company requesting to include the CVR Program in the EWR Program?

A. Not at this time. The Company believes that CVR savings align well with EWR and could be included in the Company's EWR Program in the future. As discussed by Company witness Sara T. Walz, the CVR Program, including the shared savings incentive supported by Company witness Henry, continues to be an economic resource for customers.

Q. Is the Company requesting that the Commission approve a CVR incentive mechanism in this case?

A. No. Although CVR with a shared savings incentive still represents an economic resource for customers, Consumers Energy is not proposing that the Commission approve the shared savings mechanism in this case. The Company continues to evaluate the best approach to recognize the energy savings and share the benefits created by CVR, and to encourage the development of CVR, through a financial performance incentive. The Company expects to propose a plan to best incentivize the development of CVR to achieve the shared benefits associated with energy and capacity savings in a future proceeding.

Q. Please describe the Company's DR Program.

A. The full deployment of the Company's business and residential DR programs in 2017 marked a milestone in its journey to provide reliable, safe, affordable, and sustainable clean energy offerings to customers. The Company integrated DR into its capacity portfolio to meet the aggressive DR Program goals in its IRP approved in Case No. U-20165. The Company continually works to achieve new learnings and to expand and improve upon its DR programs, making significant advancements in building a transformative, cost-effective DR capacity resource. Consumers Energy's DR programs help customers save money and reduce the Company's need to purchase, produce, and deliver additional energy at peak times, when prices are high. Through its DR portfolio, Consumers Energy also offers its customers an opportunity to build energy awareness, save money, and understand energy price signals. Consumers Energy takes pride in its environmental leadership and commitment to managing customer bill impacts responsibly. The Company's DR portfolio achievements also exemplify its commitment to customers and communities by providing a wide variety of choices to meet energy needs throughout Michigan. DR programs have delivered significant benefits to Michigan, including:[2]

- Accumulated demand reduction of 473.9 MW by December 31, 2020, exceeding the 451 MW projection from the Case No. U-20165 IRP;
- 145,849 enrolled business and residential customers;
- A Smart Thermostat Program which the Company operationalized in 2020, exceeding customer enrollment targets; and
- Positive customer satisfaction with residential DR programs achieving a rating of 9.1, 8.7, and 9.2 for the call center, website, and installation experience respectively for the 2020 Air Conditioning Peak Cycling Program. The Dynamic Peak Pricing program achieved ratings of 8.2 and 8.6 for the call center and website experience, respectively (based on a 10-point scale, where 1 meant not at all satisfied and 10 meant very satisfied).

For further details on the Company's DR programs, please see the direct testimony of Company witness Emily A. McGraw.

Q. How is DR included in the Company's IRP in this case?

A. DR programs help manage capacity without the need for additional supply-side electricity generation or entering into capacity contracts. They provide a flexible, repeatable, and scalable capacity resource. The DR Program benefits all customers by reducing the need to purchase additional capacity during times of peak demand, and thus reducing the cost of

[2] See the Company's 2020 DR Reconciliation filing in Case No. U-21080, available at: https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000OpNv6AAF.

providing power to all customers. As supported by Company witness McGraw, the Company developed a projected level of DR and associated costs for 2021 through 2040 that is included in the PCA. By 2031, the Company projects that it will provide 700 MW of DR. While this represents a reduction from the levels included in the Case No. U-20165 IRP, the 700 MW represents a significant, cost-effective resource that reduces the need to construct additional supply resources.

Q. Please describe the VGP programs?

A. Beginning in 2005 and continuing into 2021, Consumers Energy has offered innovative renewable energy programs. In 2005, the Company offered Green Generation as the first renewable energy program in Consumers Energy's service territory. In 2015, one of the first community solar programs in Michigan was added through our Solar Gardens Program. Furthermore, in 2017, the Company added yet another new type of renewable energy program via the new Large Customer – Renewable Energy Pilot ("LC-REP") Program. In 2020, the Company grew the product portfolio with the approval of new Renewable Energy Credit ("REC") options, the addition of our income-qualified Sunrise option to the Solar Gardens Program, and the expansion of the LC-REP Program. This broader list of options demonstrates our commitment to providing customers with the flexibility they need to meet their sustainability goals. Please see the testimony of Company witness Sarah R. Neilson for further detail on the VGP programs.

Q. How do VGP programs contribute to the Clean Energy Plan goals?

A. The VGP Program allows our customers with clean energy goals the ability to offset their usage with renewable energy at an accelerated rate. This in turn allows the Company to increase the overall amount of renewable energy in its supply portfolio. From 2005 through

2020, the VGP programs have helped to offset 1,447,195 MWh and over 1 million metric tons of carbon dioxide, which is equivalent to approximately 2.6 billion miles driven by a passenger vehicle.

Q. How are the VGP programs incorporated into the IRP in this case?

A. As described in Company witness Neilson's testimony, the VGP MWh planning scenarios that are in included in the IRP modeling are consistent with the 2019 biennial VGP programs filing in Case No. U-20649.

Q. Please describe how the Company is supporting the expansion of the EV market in Michigan.

A. The Company is currently undertaking the PowerMIDrive and PowerMIfleet pilots. Beginning in June of 2019, the Company established the PowerMIDrive pilot which is focused on: (1) serving residential customers by incenting off-peak charging in their home to maximize the grid benefits of EVs; and (2) reducing barriers to entry for residential customers via convenient public charging infrastructure located throughout the electric service territory, which covers the majority of Michigan's lower peninsula. Over the first planning year of PowerMIDrive, the Company increased EV charging capabilities with rebates for home, Level 2 public chargers and Direct Current Fast Chargers ("DCFC"). The pilot also showed that 90% off-peak charging occurred during the week and 75% off-peak charging occurred on the weekend. In addition, the Company conducted over 30 public EV engagement events.[3] Beginning in 2021 the PowerMIFleet pilot will focus on assisting non-residential customers achieve grid benefits and cost savings via optimized fleet EV use and charging, sharing the lessons learned via the concierge analyses to assist

[3] https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000D3t95AAB

future EV fleet customers with such endeavors, and assisting Consumers Energy with planning for future fleet electrification infrastructure. In addition, the Company has projected funding in Case No. U-20963 to undertake a pilot to evaluate shifting its fleet to EVs. The benefits of this pilot will include the formation of a plan to achieve the Company's goal to electrify its fleet. In addition to supporting sustainability goals, this transition will validate the operational capability of the fleet EVs while supporting Michigan-based vehicle manufacturers, who have made significant commitments toward the advancement of electrification. Please see Company witness Neilson's direct testimony for additional information on the Company's support of EV market expansion.

Q. How is the EV market growth captured in the IRP in this case?

A. As described in Company witness Neilson's direct testimony, the EV market is growing in Michigan and the Company has projected EV adoption to exceed 84,000 EVs by 2030. EV growth will inevitably lead to load growth within the Company's service territory, but this growth can be mitigated through off-peak charging programs for customers. The Company will continue to closely monitor the growth trend in the EV market to assure alignment with the IRP planning process.

Q. Please summarize your testimony.

A. Customer programs such EWR, DR, VGP, and the expansion of the EV market, play a significant role in meeting the Company's commitment to the Clean Energy Plan. EWR and DR provide cost-effective energy savings and load reduction that offset the need to construct additional supply-side resources while simultaneously saving customers money. The VGP Program allows customers to meet their clean energy goals and can accelerate the adoption of renewable energy in Michigan. Support for EV market expansion through pilots and programs such as PowerMIDrive and PowerMIFleet promotes an accelerated transformation of the Michigan transportation industry while promoting off-peak charging to limit the impact on load growth.

Q. Does this conclude your direct testimony?

A. Yes.

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 Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))))	Case No. U-21090

DIRECT TESTIMONY

OF

STEVEN Q. MCLEAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

Q. Please state your name and business address.

A. My name is Steven Q. McLean, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and what is your present position?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Director of Customer Experience Regulatory Strategy, Reporting and Quality in the Clean Energy Products Department.

Q. Please review your educational background.

A. I earned a Bachelor of Science in Political Science and Economics from Central Michigan University in May 2003. I earned a Master of Arts in Economics from Central Michigan University in December 2007.

Q. Please review your business experience.

A. In January 2006, I joined the Michigan Public Service Commission ("MPSC" or the "Commission") where I held various positions of increasing responsibility. In 2011, I was promoted to the Manager of the Rates and Tariffs section. The responsibilities of that section included, but were not limited to, analyzing utility reports, financial records, and rate case filings to determine the appropriate level of rates for regulated energy utilities utilizing laws, regulations, and Commission policies. In August of 2014, I was hired by SEMCO Energy Gas Company ("SEMCO") as the Rates and Regulatory Affairs Manager. In December of 2016, I was promoted to Director of Regulatory Affairs. As Director of Regulatory Affairs, I was responsible for all state and federal regulatory matters for SEMCO. In addition, I was responsible for the Company's Energy Waste Reduction ("EWR") program. In September of 2019, I was hired by Consumers Energy as the

Director of Customer Experience Regulatory Strategy, Reporting and Quality within the Clean Energy Department.

Q. What are your responsibilities as the Director of Customer Experience Regulatory Strategy, Reporting and Quality?

A. In this position I am responsible for coordinating the regulatory filings, reporting, and quality processes associated with the Company's EWR Plans, Voluntary Green Pricing programs, and residential Demand Response ("DR") programs.

Q. Have you previously testified before the MPSC?

A. Yes. I have testified before the MPSC in numerous general rate cases, Gas Cost Recovery cases, EWR cases, and other miscellaneous proceedings on behalf of the MPSC Staff and SEMCO. In addition, I have filed testimony on behalf of the Company in the following proceedings:

U-20650	General Gas Rate Case;
U-20697	General Electric Rate Case;
U-20766	2019 DR Reconciliation Case; and
U-21080	2020 DR Reconciliation Case.

Q. Please explain the purpose of your direct testimony in this proceeding.

A. The purpose of my direct testimony is to provide projected EWR savings and costs and describe the Company's ability to deliver the annual EWR savings included in the Company's Proposed Couse of Action ("PCA"). In addition, I address the impact of heating electrification on the Company's demand forecast.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibit:

Exhibit A-80 (SQM-1)	Annual Energy Waste Reduction Savings and Investments.

Q. Please describe the contents of Exhibit A-80 (SQM-1).

A. Exhibit A-80 (SQM-1), lines 1 through 3, show the actual annual EWR (or energy efficiency) annual savings for 2009 through 2020 and projected savings for 2021 through 2040. Line 4 shows the annual percent energy savings per year, which was calculated as the ratio of annual energy efficiency savings divided by the retail energy sales from the previous year. Exhibit A-80 (SQM-1), lines 5 through 7, show the actual annual Summer Coincident Peak Demand Savings (MW) for 2009 through 2020 and projected Summer Coincident Peak Demand Savings (MW) for 2021 through 2040. Exhibit A-80 (SQM-1), lines 8 through 11, show the actual annual Operations and Maintenance ("O&M") investments (including the financial incentive) for 2009 through 2020 and projected O&M investments for 2021 through 2040. Line 12 shows the cost of conserved energy associated with the investments each year.

<u>SECTION I: EWR SAVINGS</u>

Q. Please describe the Company's actual progress in helping customers reduce energy waste since 2009.

A. Beginning in 2009, the Company committed to deliver a robust set of EWR programs that would make a meaningful difference for customers by helping them reduce electric and gas energy waste. However, it took time to develop and implement programs that could deliver more than at least 1.0% of energy savings per year. The Company refined its programs over the years to increase the amount of energy savings from 0.3% in 2009 to 1.0% in 2012 through 2016. In 2017, the Company increased the level of energy savings from 1.0% per year to 1.5% per year as part of its commitment to cost-effectively reduce customer energy waste and improve the environment. Consistent with the Company's Integrated Resource Plan ("IRP") in Case No. U-20165, the Company has increased energy savings from 1.5% per year to 1.8% in 2020. Beginning in 2021, the Company is targeting 2.0% annual savings. From 2009 to 2020, the Company's EWR programs totaled $3.9 billion in energy savings. As part of the Company's PCA in this proceeding, the Company projects an additional $22.4 billion in energy savings through the planning period, with EWR savings averaging 1.9% for the 2021 through 2040 period.

Q. How were the EWR savings identified in Exhibit A-80 (SQM-1) incorporated in the IRP modeling?

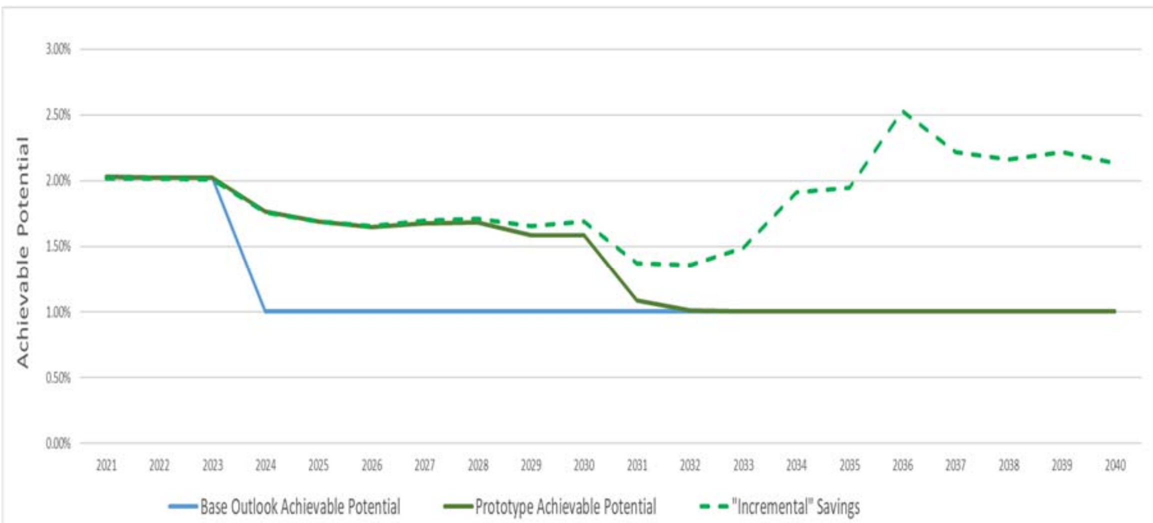
A. Exhibit A-80 (SQM-1) illustrates what the industry terms as incremental savings. The term incremental in this context is distinct from the incremental term used to describe the additional incremental savings above the Company's base outlook of EWR savings used in the Company's modeling and scenarios described by Company witness Sara T. Walz, the PCA, and the Alternate Plan. As discussed by Company witness Lakin H. Garth, the incremental savings serve as the basis for EWR Plan filings and targets, consistent with industry best practices and the recommendations of the National Action Plan for Energy Efficiency. The IRP modeling is based on cumulative potential savings which are a subset of the incremental savings. Cumulative potential accounts for measures that are converted during early years of the analysis but reach the end of their effective useful life before the end of the 20-year analysis timeframe, are re-installed with a like-for-like technology, by accruing no additional savings compared to the baseline forecast. Incremental potential accounts for measures that are converted during early years of the analysis but reach the end of their effective useful life over the 20-year analysis timeframe, are re-installed with a like-for-like technology, by accruing the same first-year energy savings values and costs as the original installation. Table 1 shows the cumulative savings included in the PCA alongside the annual incremental savings.

Table 1

Year	Cumulative Potential (MWh)	Incremental Potential Prototype (MWh)
2021	657,200	657,200
2022	654,300	654,300
2023	653,000	653,160
2024	569,200	569,699
2025	543,600	545,305
2026	526,300	530,202
2027	534,800	540,374
2028	537,300	544,048
2029	504,300	525,098
2030	508,300	540,297
2031	346,600	436,864
2032	329,300	442,059
2033	328,900	489,576
2034	331,400	627,879
2035	330,400	636,926
2036	323,500	810,078
2037	321,100	706,973
2038	319,200	682,750
2039	318,400	699,268
2040	322,000	680,017
Total	8,959,100	11,972,074

The EWR potential was modeled in the 2021 IRP in two ways. The cumulative base outlook was entered as a load modifying resource that is incorporated into the load forecast and therefore a “must-take” input into the model. The Company also developed a prototype scenario that was above the base outlook. The additional MWh from the prototype was entered as a resource that is “selectable” by the model, based on forecast EWR costs and maximum achievable potential incremental to “must-take” amounts. For both approaches, Consumers Energy assumed EWR of 2% of the previous year's sales for 2021 through 2023 and 1.0% EWR in the base load forecast from 2024 through 2040, and developed a prototype representing incremental potential above the 1.0% cumulative of sales. The below graph illustrates the percentage of prior year savings for the annual cumulative base and Prototype that represent the achievable potential in the PCA. The graph also includes the annual incremental savings that will be the targets for the annual EWR filings and are included in Exhibit A-80 (SQM-1).

Graph 1



Q. How did the Company decide on these savings levels?

A. The Company chose the levels included in the PCA based on a combination of factors including historical program performance, the EWR savings levels included in the IRP in Case No. U-20165, the results of recent market potential studies included in the U.S. Department of Energy ("DOE") energy efficiency catalog,[1] and the Electric EWR Potential

[1] https://www.energy.gov/eere/slsc/energy-efficiency-potential-studies-catalog

Study developed by Cadmus and supported by Company witness Garth ("2021 Potential Study").

Overall, for 2021 through 2040, the PCA includes 8,959,100 MWh of cumulative EWR achievable potential, which represents 21.57% savings relative to the baseline forecast. The average annual maximum achievable potential expressed as a percentage of forecast annual MWh sales included in the PCA is 1.1% per year, calculated by dividing the total cumulative savings percentage (21.57%) over the IRP period by the number of years (20 years).

This is comparable to the 2021 Potential Study average annual maximum achievable potential of 0.83% per year, calculated by dividing the total cumulative savings percentage (16.5%) over the study period by the number of years in the study (20 years).

As described by Company witness Garth, the DOE maintains a database of energy efficiency potential studies completed between 2010 and 2020. Of the 31 studies presenting achievable potential with a first study year between 2017 and 2022, the annual potential savings rate ranges from 0.2% to 2.7%, with an average achievable potential equal to 1.0% of sales. The results of both the Company's Prototype and the 2021 Potential Study fall within the range of the state and local EWR potential studies in the DOE database and are near the average value for studies presenting achievable potential with a first study year between 2017 and 2022.

Q. Please describe any challenges or risks associated with achieving the EWR savings levels included in the PCA.

A. Potential studies are a forecast of future EWR savings. Like any forecast, there is an implied range of uncertainty distributed around each predicted value. This uncertainty includes changes in building code standards, technology, forecasted avoided costs, and projected customer response. Various assumptions can impact the level of potential, such as assumptions about the treatment of future emerging technologies and the level of avoided costs. As described by Company witness Garth, there are also execution risks associated with achieving the savings included in the 2021 Potential Study that may impact the Company's ability to achieve the savings levels included in the PCA. Given the uncertainties in the potential energy savings, the Company believes its projected levels for delivering energy savings are reasonable. The Company will continue to evaluate the potential energy savings as part of future IRP proceedings, and may adjust the level of energy savings as necessary.

Q. How confident is the Company in achieving energy savings identified in Exhibit A-80 (SQM-1) as part of the PCA?

A. Subject to continued evaluation and adjustment as necessary in future IRPs, the Company is confident that it can overcome the challenges and risks to achieve the energy savings levels reflected in Exhibit A-80 (SQM-1) for four reasons: consistency in delivery, robust network, leveraged national expertise, and market potential. First, the Company's planning and implementation strategies have allowed it to consistently deliver the energy savings approved by the Commission in its EWR Plans since 2009. Second, the Company has built a robust trade ally network of over 2,000 engaged business partners who have been instrumental in helping it succeed in reducing customer energy waste. Third, the Company leverages the expertise of nationally recognized Implementation Contractors to assist it in designing, planning, and implementing EWR programs in Michigan. And fourth, as previously noted, the average cumulative savings potential included in the PCA is in line with the 2021 Potential Study and other recent potential studies. For these reasons, the Company reasonably expects to achieve the projected energy savings level included as part of the Company's PCA.

Q. Will the Company continue to pursue 2.0% annual savings as part of the EWR program?

A. The Company will continue to pursue 2.0% savings in the biennial EWR plan filings so long as it is achievable and cost effective. The EWR planning and reconciliation process allows the opportunity for review and approval of EWR savings and costs on an ongoing basis.

<u>SECTION II: ADDITIONAL EWR SCENARIOS</u>

Q. Please describe the Transformational Technology Scenario included in the 2021 Potential Study.

A. As described by Company witness Garth, the Company had Cadmus develop the transformational technology scenario to identify the savings potential that Consumers Energy could capture by being even more aggressive and by strategically researching, supporting, and implementing emerging energy-efficiency technologies, alternative delivery strategies, and other new energy-efficiency opportunities. The Company will use the information provided in this scenario to help inform future EWR planning efforts. Please see Company witness Garth's testimony for further information on the transformational technology scenario. The cumulative savings from the transformational technology scenario were incorporated into the Advanced Technology scenario supported by Company witness Walz.

Q. Please describe the savings levels included in the MPSC required scenarios.

A. For the MPSC required scenarios, Consumers Energy assumed EWR savings of 2% of the previous year's sales for 2021 through 2023 and 1.5% of sales in its base load forecast from 2024 through 2040. These savings were treated as incremental annual savings, and the cumulative achievable potential was calculated by implementing measure life expiration based on the average measure life by year, included in the 2021 Potential Study.

Q. Did the Company make any adjustments to the PCA cumulative savings relative to the other scenarios and sensitivities?

A. Yes. The Company originally created cumulative potential savings for the IRP which excluded like-for-like replacement savings by implementing measure life expiration relative to the annual cumulative savings. While developing the PCA, the Company determined that inclusion of the like-for-like replacement savings would result in more accurate EWR savings potential. Inclusion of the like-for-like replacement savings prevents the cumulative achievable potential from decreasing relative to the baseline forecast as measures reach end of life. As previously discussed, the like-for-like replacement savings do not increase EWR cumulative savings relative to the baseline forecast, but are a necessary component of the incremental savings and are included in the annual EWR targets in the Company's biennial EWR plan filings. Inclusion of the replacement savings results in higher cumulative savings in the PCA relative to other Consumers Energy scenarios and sensitivities.

SECTION III: EWR INVESTMENT

Q. Has the Company allocated the investment needed to deliver on these increased energy saving goals?

A. Yes. The Company included all investments associated with implementing its portfolio of EWR programs, including administrative; customer incentives; customer education; Evaluation, Measurement, and Verification ("EM&V"); pilots; and a financial performance incentive.

Q. How did the Company determine the annual investment needed to deliver these energy savings goals?

A. The Company used the underlying cost assumptions included in the 2021 Potential Study, which were informed by program history and industry benchmarking, adjusted to reflect the higher level of cumulative savings included in the Company's PCA for both the base outlook and incremental prototype. In addition, the Company added 5% additional cost for the pilot programs and 3% additional cost for education and awareness. The incremental investments for the PCA are shown on Exhibit A-80 (SQM-1), line 9, and the total investments including the financial incentive are shown on line 11.

Q. Is the Company's projected EWR investment cost-effective?

A. Yes. At an average cost of conserved energy of 2.5¢ to 4.3¢ per kWh, the EWR programs represent a low-cost and cost-effective resource.

Section IV: Approval of Incremental Investment

Q. Is the Company requesting approval of the projected incremental investments as reasonable and prudent for cost recovery purposes to deliver these increased energy savings levels as part of this proceeding?

A. Yes, the Company requests such approval of the EWR investment and performance incentive that will occur within the time period July 1, 2022 through June 30, 2025 that is incremental to the costs approved in the Company's 2020-2023 EWR plan filing in Case No. U-20372. As shown on Exhibit A-80 (SQM-1), lines 8 through 11, these costs consist of incremental O&M investment for 2024, and the prorated six months of 2025, of $119.5 million; Base Outlook O&M investment for 2024, and the prorated six months of 2025, of $107.2 million; and a financial incentive for 2024 and the prorated six months of 2025, of $45.3 million. The total investment and financial incentive for 2024 and the prorated six months of 2025 is $272.1 million. Consistent with the process followed since 2009, the Company will refine these projections as part of its EWR Plans filed with the Commission every two years. This will include providing details on the portfolio goals, a description of each program in the portfolio, energy savings, investment levels, cost-effectiveness test results, portfolio implementation and management details, and EM&V information. As discussed, the Company will continue to pursue 2.0% savings, and include the associated costs, in the biennial EWR plan filings so long as it is achievable and cost effective.

Q. When is the next required EWR Plan filing?

A. The Company's next EWR Plan will be filed on August 1, 2021, for the period 2022 through 2025.

Q. If there are changes to the Michigan market that impact the Company's ability to deliver energy savings, will the Company address these in its EWR Plan filings?

A. Yes. Changes to codes and standards or evaluation studies that impact energy savings values will be addressed as part of the Company's regular EWR filings.

Section V: Heating Electrification

Q. Did the Company perform an analysis of the impact of heating electrification on the demand forecast consistent with the settlement agreement approved in Case No. U-20165?

A. Yes. The Company worked with Cadmus to develop an analysis of the impact of heating electrification for the 2021 through 2040 timeframe. As part of this analysis, the Company determined that adoption rates are currently low in Michigan. While the adoption rates may increase over time, the overall impact of heating electrification remained minimal over the 2021 through 2040 timeframe. Based on this analysis, the Company determined that the level of MWh load additions was minimal and would not have a meaningful impact to the overall load forecast. The Company will continue to monitor industry changes related to heating electrification.

Q. Does this conclude your direct testimony?

A. Yes.

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

DIRECT TESTIMONY

OF

LAKIN H. GARTH

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

Q. Please state your name and business address.

A. My name is Lakin H. Garth. My business address is 205 Queens Road, Athens, GA, 30606.

Q. Please describe your position and responsibilities.

A. I have been employed by The Cadmus Group, Inc. ("Cadmus") since 2012. My title is Principal in the Energy Services sector, which provides program and market analysis, statistical and economic analysis, measurement and engineering, and broad utility services across three practice areas: energy program performance, strategic electrification, and distributed energy and renewables. Cadmus's energy program performance work largely focuses on quantifying savings and assessing the performance of energy efficiency programs for utilities across North America. We currently employ over 160 Demand Side Management ("DSM") professionals in 16 offices in the U.S. and Germany. Our clients include investor-owned and public utilities, public utility commissions, state agencies, and international organizations. We currently deliver energy efficiency planning services in Michigan, Georgia, Oregon, Washington, Colorado, Wisconsin, New York, Kentucky, and Virginia. At Cadmus, I lead a team of 10 analysts, researchers, and program design experts and serve as the principal in charge for numerous energy efficiency potential study, program planning, and cost-effectiveness projects. This work includes project planning and management, strategic planning, policy analysis and regulatory support, oversight of research and analysis work, and quality control.

Q. Please describe your education and professional experience.

A. I hold a Bachelor's in Business Administration degree in International Business from the University of Georgia and a Master of Science degree in Economics from Portland State University. Prior to my present position with Cadmus, I was a senior planning project manager in the planning and evaluation group at the Energy Trust of Oregon. In my career at Cadmus, I have performed and directed dozens of DSM potential studies and assessments.

Q. What is the purpose of your direct testimony in this proceeding?

A. The primary purpose of my direct testimony is to explain the approach used by Cadmus to develop the study to quantify the amount of electric Energy Waste Reduction ("EWR") and demand reduction from EWR achievable within Consumers Energy Company's ("Consumers Energy" or the "Company") service territory from 2021 to 2040 ("2021 EWR Potential Study") and the results of this study.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes, I am sponsoring the following exhibit:

Exhibit A-81 (LHG-1) 2021 EWR Potential Study.

Q. Has this exhibit been prepared by you or under your supervision?

A. Yes.

Q. What were the objectives of the 2021 EWR Potential Study?

A. The primary objective of the 2021 EWR Potential Study was to produce a 20-year forecast of EWR potential for use in Consumers Energy's 2021 Integrated Resource Plan ("IRP") and to inform EWR program offerings for residents and businesses. The study accounted for a number of updates to the EWR market within Consumers Energy's service territory since the previous EWR study was published in 2017 for the Company's 2018 IRP. These updates included:

- New Consumers Energy-specific electric energy and customer forecasts, avoided cost forecasts, and EWR program achievements;

- Customer characteristics, including updated commercial and industrial building stock and market characteristics data and energy efficiency technology and market data; and

- Other key considerations, including alignment between recent EWR program and incentive costs and the program and incentive cost assumptions used to model EWR potential, program-specific potential including for income-qualified customers, updated federal equipment standards, and rapidly changing technology markets, such as for commercial lighting.

Q. What are Cadmus's experience and qualifications for conducting a potential study?

A. Headquartered in Waltham, MA, Cadmus is a consulting firm with more than 500 employees that has been in business since 1983. Cadmus provides many consulting services, including energy efficiency program planning and evaluation. Cadmus has performed more than 75 energy efficiency potential studies in the U.S. and numerous other DSM resource studies for investor-owned utilities, public power utilities, state utility commissions, and federal and state agencies.

Q. What was the methodology?

A. The Summary of Methodologies chapter in the 2021 EWR Potential Study, Exhibit A-81 (LHG-1), provides a detailed description of the methodology used to develop estimates of technical, economic, and achievable electric EWR potential for customers in Consumers Energy's service area. Cadmus applied a combined top-down/bottom-up approach. For the top-down component, Cadmus began with the most current sales forecasts – excluding future, planned EWR savings and adjusting for building codes, equipment efficiency standards, and market trends that the forecast did not account for – and disaggregated this information into customer sectors, segments, and equipment end uses. For the bottom-up component, Cadmus considered the technical impacts of various EWR measures on each end use, then estimated overall impacts based on engineering calculations, accounting for fuel shares, current market saturations, technical feasibility, and costs. Cadmus assessed four types of EWR potential:

- Technical potential assumes that all technically feasible EWR measures generally available at the time of the study will be implemented, regardless of their cost or other market barriers. Cadmus estimated this theoretical upper bound of available EWR potential after accounting for technical constraints;

- Economic potential represents a subset of technical potential and consists only of measures meeting the cost-effectiveness criteria, set to be consistent with the primary cost-effectiveness test adopted under Michigan Public Act 295 of 2008 (“Act 295”), as amended by Public Act 342 of 2016. Act 295 established that the primary benefit/cost test for Michigan is from the viewpoint of the utility, referred as the utility cost test (“UCT”). For each EWR measure, the Cadmus team structured the benefit/cost test as the ratio of net present values for the measure’s benefits and costs, using inputs from Consumers Energy. The study identified only measures with a benefit/cost ratio of 1.0 or greater as cost-effective;

- Maximum achievable potential represents the portion of economic potential that might be achieved after accounting for market barriers that impede customer adoption, including limitations in customers’ financial wherewithal, program awareness, and willingness to adopt EWR measures. The maximum achievable potential assumes lifting the cap that currently limits home energy report program participation; to determine the maximum achievable potential, we assumed 60% of eligible single family electric service customers would receive home energy reports. A comprehensive set of EWR measures—including market-ready technologies that are available in Michigan not currently offered by Consumers Energy programs spanning the residential, commercial, and industrial sectors—comprised the maximum achievable potential. This report expresses gross maximum achievable savings potential at the meter; and

- Program achievable potential consists of the subset of economic potential for measures currently offered and measures that have potential to be offered during the study horizon by Consumers Energy. Program achievable potential also assumes the behavioral savings cap is lifted, and Consumers Energy is able to expand the home energy report program. This report expresses program achievable potential in net savings, accounting for the current net-to-gross factors applied at the measure level, to determine Consumers Energy program impacts.

Q. What data did you use?

A. Cadmus developed EWR potential using a range of Michigan- and utility-specific data sources including the following: Michigan Energy Measures Database ("MEMD") and supporting workpapers; Consumers Energy-specific commercial and residential building stock data and appliance saturation studies; utility-specific forecasts of avoided costs for electricity, other fuels, and economic inputs; utility-specific historical and forecast data on customers, energy sales, and peak demand. Other regional and national data sources were utilized, as needed.

Q. How do the potential study and methods align with industry best practices?

A. The 2021 EWR Potential Study's methodology aligns with best practices outlined in key industry publications and used as standard practice by U.S. utilities for many years. Published in 2007, the National Action Plan for Energy Efficiency ("NAPEE") Guide to Conducting Energy Efficiency Potential Studies provides a general methodological framework for energy efficiency potential studies. The 2021 EWR Potential Study aligns with this guide, using generally accepted industry best practices in the following ways:

- The 2021 EWR Potential Study determined an accurate and Consumers Energy-specific representation of baseline energy use by sector and segment. The study established customer counts and sales, as well as forecasts, and disaggregated the baseline year (2020) sales and customer counts by sector using 2019 sales data, applying primary and secondary data to further disaggregate energy usage by end use;

- The 2021 EWR Potential Study considered several hundred commercially available EWR measures, sourced primarily from the 2020 MEMD, supplemented with additional EWR measures from secondary sources, including regional and national sources;

- The 2021 EWR Potential Study accounted for current and known future energy building codes and federal standards in its measure characterization, thereby avoiding double counting of EWR measure savings attributable to codes and standards;

- The 2021 EWR Potential Study estimated economic potential using the UCT as the primary cost-effectiveness test for determining the economic potential, consistent with Michigan Public Service Commission requirements. The UCT examines the cost and benefits of an EWR measure or program from the program implementor's perspective. For the purposes of this study, the Cadmus team included only utility incentive cost when screening measures on an individual basis. Measure incentive levels were based on recent program offerings and consistent with the most recent EWR Plan filing; and

- The 2021 EWR Potential Study established the annual cumulative maximum achievable potential which can be used as a direct input into the IRP, consistent with the guidance provided in the NAPEE Guide to Conducting Energy Efficiency Potential Studies, which states:

> It is important to distinguish between incremental savings and cumulative savings when reporting the future effects of a program. The cumulative energy or demand savings each year is more relevant to comparisons with load forecasts and for power planning purposes, while the incremental savings are more closely correlated with program spending in any given year, as the full cost of the measure is usually borne at the time of installation.

Q. How does your forecast align with newer recent potential studies conducted in similar states by Cadmus and other consultants?

A. The average annual maximum achievable potential expressed as a percent of forecast annual MWh sales presented in the study is 0.83% per year, calculated by dividing the total cumulative savings percentage (16.5%) over the study period by the number of years in the study (20 years).

In its energy efficiency potential studies catalog, the U.S. Department of Energy ("DOE") maintains a database of energy efficiency potential studies completed between 2010 and 2020.[1] Of the 31 studies presenting achievable potential with a first study year

[1] https://www.energy.gov/eere/slsc/energy-efficiency-potential-studies-catalog

between 2017 and 2022, the annual potential savings rates range from 0.2% to 2.7%, with an average achievable potential equal to 1.0% of sales.

The results of the 2021 EWR Potential Study fall within the range of all the state and local EWR potential studies in the DOE database and is near the average value for studies presenting achievable potential with a first study year between 2017 and 2022.

Q. What does the Cadmus potential study forecast for reasonable and cost-effective levels of EWR?

A. The 2021 EWR Potential Study examined several hundred EWR measures in the residential, commercial, and industrial sectors and quantified the amount of EWR potential within Consumers Energy's service territory from 2021 to 2040. The potential study identified 6,714,807 MWh of cumulative maximum achievable potential by 2040, equal to 16.5% of forecasted, baseline electric sales in 2040.

The potential study also identified 11,505,273 MWh of incremental maximum achievable potential by 2040, equal to an average annual savings of 1.75% of forecast total annual energy sales each year from 2021 to 2040.

Q. What is the difference between cumulative and incremental potential?

A. Cumulative potential accounts for measures that are converted during early years of the analysis but reach the end of their effective useful life before the end of the 20-year analysis timeframe, are re-installed with a like-for-like technology, by accruing no additional savings compared to the baseline forecast. Incremental potential accounts for measures that are converted during early years of the analysis but reach the end of their effective useful life over the 20-year analysis timeframe, are re-installed with a like-for-like technology, by accruing the same first-year energy savings values and costs as the original installation. The cumulative savings are consistent with the EWR savings modeled by Consumers Energy for its IRP whereas the incremental savings serve as the basis for EWR Plan filings and targets, consistent with industry best practices and the recommendations of the NAPEE. Table 1 shows the cumulative and incremental maximum achievable potential identified by the EWR potential study.

Table 1

Year	Cumulative Potential (MWh)	Incremental Potential (MWh)
2021	679,707	679,707
2022	626,934	707,706
2023	603,406	713,122
2024	435,358	569,366
2025	425,289	544,649
2026	426,035	529,415
2027	441,955	536,055
2028	443,564	538,837
2029	410,879	520,149
2030	415,694	536,187
2031	255,380	433,997
2032	238,900	440,011
2033	187,183	436,189
2034	179,176	563,992
2035	170,960	565,804
2036	161,763	736,610
2037	157,646	631,712
2038	156,459	608,177
2039	151,226	620,222
2040	147,293	593,364
Total	6,714,807	11,505,273

Q. Does the 2021 EWR Potential Study use the UCT?

A. Yes. Cadmus estimated economic potential using the UCT. Section 13(d) of Act 295 defines the UCT, or the Utility System Resource Cost Test, as:

> a standard that is met for an investment in energy waste reduction if, on a life cycle basis, the total avoided supply-side costs to the provider, including representative

> values for electricity or natural gas supply, transmission, distribution, and other associated costs, are greater than the total costs to the provider of administering and delivering the energy waste reduction program, including net costs for any provider incentives paid by customers and capitalized costs recovered under section 89.

Section 73(2) of Act 295 also states that:

> [t]he commission shall not approve a proposed energy waste reduction plan unless the commission determines that the energy waste reduction plan meets the utility system resource cost test and, subject to section 78, is reasonable and prudent.

In addition to screening individual EWR measures for cost-effectiveness using the UCT, Cadmus calculated the maximum achievable potential UCT benefits and costs for the residential and business sectors individually and combined. The UCT benefit/cost ratio for the combined sectors is 1.69.

Q. What does the 2021 EWR Potential Study suggest are execution risks associated with achieving the EWR energy savings included in the Company's Proposed Course of Action ("PCA")?

A. The potential study findings suggest the following possible execution risks for achieving the EWR energy savings included in the PCA:

- Commercial and industrial lighting opportunities contribute significant, cost-effective EWR potential, but data collected for Consumers Energy's 2020 commercial market assessment reveal dramatically higher Light-Emitting Diode ("LED") penetration across all commercial segments compared with data collected in 2015. The increase in LED market adoption reduces savings potential from this market segment;
- Advanced and emerging residential measures, including advanced Heating, Ventilation, and Air Conditioning and other mechanical equipment, offer substantial long-run, cost-effective EWR potential yet represent a smaller portion of Consumers Energy's historical savings compared to their relative contribution to maximum achievable potential. Meeting the EWR energy savings targets in the PCA may require intervention to increase the adoption of these advanced technologies by program participants; and

- Industrial process measures contribute significant, cost-effective EWR potential. The industrial sector, which represents 28% of 2040 forecasted baseline sales, represents significant cost-effective EWR potential, led by a wide range of process measures across all manufacturing facility types. Process measures account for 39% of the total, 20-year industrial maximum achievable potential and 15% of total nonresidential savings. Maintaining progress toward IRP targets will require continued success in acquiring program savings from this market segment, especially as economic activity increases during the post COVID-19 recovery period.

Q. Did Cadmus develop a transformational technology scenario?

A. Yes. The transformational technology scenario incorporates dozens of emerging and innovative technologies in various stages of development to estimate the magnitude, timing, and costs of savings potential. Cadmus developed the transformational technology scenario to identify the savings potential that Consumers Energy could capture by being even more aggressive and by strategically researching, supporting, and implementing emerging energy-efficiency technologies, alternative delivery strategies, and other new energy-efficiency opportunities. The transformational technology scenario incorporated emerging technology options identified by Consumers Energy, its vendors, national research teams, and industry experts from across the country. Cadmus compiled, reviewed, characterized, and prioritized these emerging technologies based on their degree of technical, economic, market, or program uncertainty.

Q. What was the methodology used to develop that scenario?

A. In the transformational technology scenario, Cadmus used a less restrictive approach—recognizing increased capital investment in clean energy technology innovation—to model certain measures that could be expected to gain market acceptance and more widespread adoption under future conditions that emphasize decarbonization, a shift toward greater nonresidential energy uses, and increased proliferation of automation, real-time monitoring, and artificial intelligence-supported and controlled building systems.

Q. What are some of the findings from that scenario?

A. Even with aggressive research and outreach, limited definitive data exist on many of the emerging technologies considered by the transformational technology scenario. The scenario required significant expert judgment on when technologies may become commercially available, likely cost trajectories, likely market adoption rates, and the savings values applied. Furthermore, the scenarios indicated that key actions – such as the following – will be required to drive innovation to realize the potential from emerging technologies:

- Technology development and demonstration. This may include investments in research and development, lab testing, and/or pilots that engage early adopters to install and use new technologies and provide feedback that will help further development and determine applicability;
- Identification of optimized delivery strategies and market intervention approaches to encourage adoption of emerging technologies at scale. This may include pilots and market forecasting to assess changes in cost as technologies are commercialized;
- Customer and trade ally outreach. Lack of awareness and knowledge are significant barriers to adoption of a new technology; outreach to, and education of, consumers helps to build interest and demand while trade ally engagement ensures that there is a qualified workforce to install and service new technologies; and
- Stakeholder review and acceptance. This may include engaging and sharing information about emerging technologies and working collaboratively with stakeholders to demonstrate energy saving potential and paths to market adoption.

Q. Does that conclude your direct testimony?

A. Yes.

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 Approval of an Integrated Resource Plan	)	Case No. U-21090
under MCL 460.6t, certain accounting	)	
approvals, and for other relief.	)	
____	)	

DIRECT TESTIMONY

OF

EMILY A. MCGRAW

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

Q. Please state your name and business address.

A. My name is Emily McGraw, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and what is your present position?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Director of Residential Demand Response.

Q. Please review your educational background.

A. I graduated from Michigan State University with a Bachelor of Science in Mechanical Engineering.

Q. Please describe your business and professional experience.

A. I started my career at Consumers Energy in 2005 as a gas engineer in a rotational program designed for recent college graduates. During this time, I rotated through four gas business units working on short-term projects.

In 2006, I took a position as a gas transmission pipeline engineer where I was responsible for designing high pressure gas pipeline facility installations.

In 2010, I took a position as a Project Manager for Gas Storage, Compression, Pipeline, and Metering & Regulation capital construction projects. There, I was responsible for managing the cost, scope, and schedule by developing project plans, managing project budgets, contractor oversight, and managing project schedules to meet equipment outage windows.

In 2014, I took a position as a Program Manager for Residential Energy Efficiency Programs and was responsible for program design, management, and coordination of energy efficiency programs to deliver energy savings goals. In 2018, I was promoted to Director of Residential Demand Response.

Q. What are your responsibilities as Director of Residential Demand Response?

A. In this position, I am responsible for the Company's Residential Demand Response ("DR") programs and pilots.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I have previously testified before the MPSC in Consumers Energy's 2018 DR Reconciliation Case, Case No. U-20563; Consumers Energy's 2019 DR Reconciliation Case, Case No. U-20766; and Consumers Energy's 2020 DR Reconciliation Case, Case No. U-21080.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to provide a description of the Company's existing and proposed DR portfolio, which includes the business and residential DR programs and the assumptions associated with the DR programs within the Integrated Resources Plan ("IRP"), as well as describing the capital cost the Company is requesting the Commission approve for DR programs as authorized by Section 6t of Public Act 341 of 2016, and explain the proposed recovery of these costs. The Company's DR programs have been incorporated into the Company's Proposed Course of Action ("PCA") based on modeling performed. As shown in Exhibit A-82 (EAM-1), under the PCA, the level of DR increases from 607 MW in 2022 to 698 MW in 2030 and then remains constant at that level through 2040.

Q. How is your direct testimony organized?

A. My direct testimony is organized as follows:

SECTION I: CURRENT DEMAND RESPONSE PORTFOLIO

SECTION II: PROJECTED COST AND MW

SECTION III: CHANGES FROM PREVIOUS FILINGS

SECTION IV: DEMAND RESPONSE PILOTS

SECTION V: EXECUTION RISKS

SECTION VI: PERFORMANCE INCENTIVE

SECTION VII: SUMMARY

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-82 (EAM-1)	Projected DR Program Size by Year;
Exhibit A-83 (EAM-2)	Projected DR Program Cost by Year;
Exhibit A-84 (EAM-3)	2020 Demand Response Annual Report; and
Exhibit A-85 (EAM-4)	Consumers Energy's 2020 Demand Response Potential Study.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

SECTION I: CURRENT DEMAND RESPONSE PORTFOLIO

Q. Please describe the Company's DR Portfolio.

A. The Company offers a DR portfolio consisting of both business and residential programs. The intent of the DR Portfolio is that collectively the reduction in peak load will relieve stress on the electric system in a more cost-effective manner than purchasing capacity from the market or building additional generation resources to meet peak demand. The 2020

DR Annual Report, Exhibit A-84 (EAM-3), provides an overview of 2020 DR programs, activities, and achievements.

Q. Please describe the business DR programs.

A. The Company has three tariff-based business DR rate programs: Interruptible Rate GI ("GI"), Interruptible Rate GI2 ("GI2"), and Energy Intensive Primary Rate ("EIP"). In addition to the three tariff-based Interruptible Rate DR programs, the Company offers a business DR Program that is a contractual program targeted towards business customers interested in curtailing demand that are not currently on an interruptible or retail open access rate. Each business customer that signs up for the contractual program is contracted for a specified load (kW) reduction during events for the program year of June 1 through September 30. The contract sets forth the program parameters, including the program period, timing and frequency of events, mandatory versus voluntary economic events, minimum advanced notification time, primary contacts to receive event notifications, how performance will be calculated, rules regarding non-performance, and the compensation the customer will receive for the capacity provided. Customers in the business DR Program affirm that their load can be reduced up to four hours per event for up to 10 events per DR season. The Company's business DR Program offers both an emergency and an economic program option. Customers can participate in the emergency program and choose to add the voluntary economic program to their contract. The Company works with business customers to set up an Energy Reduction Plan ("ERP") at their facilities that will be implemented when a DR event is called. These DR events are initiated by the Midcontinent Independent System Operator, Inc. ("MISO") during times of system emergencies, i.e., a time when electricity demand and cost are highest. A number of business customers of different sizes are enrolled through this process to create a resource that can be called upon during peak times of system usage to reduce overall electricity demand. When MISO expects the grid to be strained because of high electric demand or during high market costs, a notification is sent out to all of the business customers within the portfolio ahead of the emergency event, informing them of when they need to reduce load. When the emergency event occurs, they follow their established ERP, thus decreasing their electric demand. Events can be emergency events called by MISO or economic events initiated by the Company to reduce or shift peak demand.

Q. How does the business DR Program differ from Interruptible rate GI and the EIP rate?

A. Both the GI and the EIP rates are filed tariffs with specific capacity and energy billing parameters, whereas the Company's business DR Program is a negotiated contract with customers for reducing demand during events. Like the GI and EIP capacity resources, the business DR Program is made up of demand curtailment commitments of a portfolio of business customers. If a business DR participant fails to deliver 100% of their total nominated kW for an Emergency Event ordered by the Company, the customer shall forego all payments if the average delivered capacity for the event is less than their contracted amount and the customer shall be assessed the real time commodity price ($/MWh), as determined by the MISO Midwest Energy Market, for the kWh curtailment which was underperformed per event. The real time commodity price is capped at $1,000/MW. There are no direct financial consequences to participants who do not shed load during economic events, other than the lack of incentive payments (i.e., payments for capacity and energy at the time the demand event is called). The financial benefit to participating business customers is less significant with the business DR Program than with a GI or EIP rate to recognize the reduced risk for customers and the reduced duration of the program as the business DR program operates June 1 through September 30th only.

Q. Please describe the methodology used to determine the trigger condition.

A. As outlined in Company witness Michael C. Grondin's direct testimony in Case No. U-20766, the Company's Electric Supply Operations Planning Department is responsible for forecasting the hourly electric load each day and for selecting and deploying the least-cost resource mix to meet that hourly load on a daily basis. To accomplish this, the Company developed market price and load levels that, when exceeded, indicate that economic DR resources should be considered and dispatched. For example, during the summer of 2020, the Company calculated the trigger conditions to be based on market prices of $75/MWh and a 4- hour load forecast exceeding 27,000 MWh. The Company's business economic DR Program is available for up to 10 system peak events over the summer. Additionally, all of the DR resources are available for up to 10 emergency events to meet MISO requirements. For planning purposes, the Company estimated 3 to 4 events per month in June through August and 1 event in September.

Q. How are business DR participants compensated for reducing their electric load during peak demand events?

A. Participants are compensated for capacity and energy reductions during events. The capacity payment is tied to kW of reduction delivered, and the energy payment is based on kWh reduction during events. Both are measured from an established baseline. Incentive payments are priced for market competitiveness and are a component of the overall cost of having and managing a DR capacity resource. These payments are made to customers through a bill credit at the end of the program season.

Q. Please describe the Company's residential DR programs.

A. In 2017, the Company launched two Commission-approved residential DR programs as part of its Peak Power Savers® Program: AC Peak Cycling and Dynamic Peak Pricing. In 2020, the Company commercialized its Smart Thermostat pilot by rapidly growing participation from 2,500 customers in 2019 to over 25,000 customers in 2020. Similar to business DR programs, the residential DR programs are designed to give the Company a flexible energy resource that can be used during times of peak electricity demand to reduce power supply costs that directly impact all of our generation customers.

Q. Please describe the AC Peak Cycling ("ACPC") Residential DR Program.

A. ACPC is a direct load control program in which the Company installs a load control switch on the outside of a customer's home on or near their central AC unit. During peak event days the Company activates the switch to cycle the output of the central AC unit to reduce load during the event. The central AC unit cooling system returns to normal once the cycling event ends. The load control peak demand reduction is achieved using the Advanced Metering Infrastructure ("AMI") and ZigBee two-way communication technology. Load management may occur any weekday (excluding holidays) between 7 a.m. and 8 p.m. for no more than an eight-hour period in any one day and may be implemented to maintain system integrity, for economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load management may only occur outside of the hours of 7 a.m. and 8 p.m. during a declared

Midcontinent Independent System Operator, Inc. ("MISO") emergency. The program is available for 5 emergency events and 10 economic events.

Q. How are customers incentivized to participate in the ACPC Program?

A. Customers enrolling in ACPC received a gift card and a monthly bill credit of $8.00 during the June 1 through September 30 DR season.

Q. Please describe the residential Dynamic Peak Pricing ("DPP") Program.

A. The Company's DPP Program was designed to encourage customers to move energy consumption to off-peak hours by providing less expensive rates at these times. In addition, the program provides incentives for customers to reduce their energy use during DR events. The more energy usage participants shift from peak hours, the more they can save.

The Company offers two DPP programs: Critical Peak Pricing ("CPP") and Peak Time Rewards ("PTR"). The goals of the two pricing options are identical, but the approach to achieve them is different. The CPP option replaces the standard on-peak energy charge participants pay with a much higher critical peak energy charge on event days in exchange for lower off-peak rates all summer long. This is generally referred to as a "stick" incentive to encourage customers to shift demand. Alternatively, the PTR option offers customers an incentive payment of $1.00 in bill credits for every kWh of energy they save during the event, compared to their typical use during those same hours. This is generally referred to as a "carrot" incentive. Load management may occur on any weekday (excluding holidays) between 7 a.m. and 8 p.m. for no more than an eight-hour period in any one day and may be implemented to maintain system integrity, for economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load management may only occur outside of the hours of 7 a.m. and 8 p.m. during a declared MISO emergency. The program is available for 14 events between June and September and 5 events between October and May.

Q. Please describe the Smart Thermostat Program ("STP").

A. The STP was launched as a pilot in 2019 and commercialized to a full-scale program in 2020. STP is a direct load control program that utilizes cloud-based software deployed through the customer's wi-fi thermostat to control the air conditioning load of residential customer's homes. The vendor software features algorithms customized on a per-home basis that balance demand reduction while maintaining individual customer comfort preferences. Load management may occur on any weekday (excluding holidays) between 7 a.m. and 8 p.m. for no more than an eight-hour period in any one day and may be implemented to maintain system integrity, for economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load management may only occur outside of the hours of 7 a.m. and 8 p.m. during a declared MISO emergency. The program is available for 9 economic events and 5 emergency events.

Q. How are customers incentivized to participate in the STP?

A. The program offers two enrollment tracks: a Bring Your Own Device ("BYOD") track; and an online marketplace track. Through the BYOD track, customers who already own an eligible smart thermostat receive an initial gift card. Through the online marketplace track, customers may purchase a new thermostat and receive an instant discount, which includes an Energy Waste Reduction ("EWR") rebate, making many thermostats free for combination-fuel customers and heavily incentivized or free for electric customers. All customers who remain enrolled in the pilot at the end of DR event season receive a $25 gift card.

SECTION II: PROJECTED COST AND MW

Q. What level of DR is currently included in the Company's base plan and in the PCA?

A. Exhibit A-82 (EAM-1) shows projected levels of DR by program type and year. In the DR plan, as shown in Exhibit A-82 (EAM-1), Consumers Energy plans to: (i) maintain the DPP at approximately 10 MW through the study period; (ii) increase A/C Cycling from approximately 45 MW in 2021 to 72 MW by 2031; (iii) increase the STP from approximately 22 MW in 2021 to 88 MW by 2031; (iv) Develop new Smart Business DPP program beginning in 2023 to increase to 13 mw by 2031; (v) increase C&I DR from 221 MW in 2021 to 315 MW by 2031; and (iv) maintain Rate GI and EIP at 2023 levels of 151 MW and 50 MW, respectively. The Company chose the levels included in the PCA based on a combination of factors, including historical program performance, DR savings levels included in the IRP in Case No. U-20165, and the Demand Response Potential Study ("Potential Study") developed by Cadmus and Demand Side Analytics ("DSA"), as illustrated in Exhibit A-85 (EAM-4). Additionally, per the requirements of the 6t statute on the Company's IRP, the Company also considered scenarios incorporating the existing State of Michigan Demand Response Potential Study ("AEG Statewide DR Study").

Q. Please describe the Potential Study, as illustrated in Exhibit A-85 (EAM-4).

A. The Potential Study aimed to achieve two primary research objectives: 1) develop estimates of demand reduction potential; and 2) provide disaggregate amounts of DR potential and the associated costs for use in the Company's IRP modeling. In addition, the

Potential Study includes best practices and DR trends in the electric industry consistent with the settlement agreement in Case No. U-20165.

Q. Please describe Exhibit A-83 (EAM-2).

A. Exhibit A-83 (EAM-2) shows historical and projected levels of capital and Operating and Maintenance ("O&M") for 2019 through 2040 that are necessary to achieve the DR MW included in the PCA. This includes capital and O&M to achieve and maintain the 607 MW included in the Company's Base Outlook along with incremental capital and O&M necessary to achieve the incremental savings included in the PCA.

Q. Please identify the DR costs the Company is requesting that the Commission determine are reasonable and prudent for cost recovery purposes in this proceeding.

A. Consumers Energy requests approval of capital costs in the amount of $23.751 million. This amount is for the period January 1, 2023 through June 30, 2025, and is incremental to the capital costs the Company has requested in its current electric rate case, Case No. U-20963. This consists of $23.2 million of Base Outlook capital expenditures, and $0.41 million of incremental capital expenditures, for 2023, 2024, and the prorated six months of 2025. The Base Outlook Capital Expenditures for 2023 forward are consistent with the levels requested in Case No. U-20963 and are necessary to maintain the 607 MW approved in the Company's 2018 IRP filing in Case No. U-20165. Consumers Energy requests approval of O&M in the amount of $3.1 million. This amount is for the period January 1, 2023 through June 30, 2025, and is incremental to the O&M expenses the Company has requested in Case No. U-20963. Consumers Energy requests approval of the performance incentive in the amount of $26.3 million. This amount is for the period May 31, 2022 through June 30, 2025, and is based on a 20% performance incentive consistent with the Company's request in the 2019 DR Reconciliation in Case No. U-20766 and with the performance incentive costs included in Potential Study and IRP modeling. The 2022 Performance Incentive is not included in Case No. U-20963 and will be recovered as part of the 2022 DR Reconciliation that will be filed in 2023.

SECTION III: CHANGES FROM PREVIOUS FILINGS

Q. Are there differences between the DR ramp-up strategy outlined in the Company's 2018 IRP and the strategy in the PCA in this filing?

A. Yes. Exhibit A-82 (EAM-1) identifies the DR included in the PCA consistent with the existing DR Program accomplishments and the Consumers Energy DR Potential Study findings. The Company's 2018 IRP called for DR resources to reach 1,250 MW by 2031. The current PCA calls for approximately 700 MW by 2031. This change is due to the impacts of EWR measures, as detailed by Company witness Steven Q. McLean, on the Company's overall load forecast and peak demand. Additionally, beginning in 2021, the Company implemented their Summer Peak Rate to all residential customers. This rate will lower residential on peak demand by 3.5%; equating to 119 MWs of on peak demand reduction included in the load forecast for the IRP analysis period, as shown in Exhibit A-82 (EAM-1) and as also detailed in the testimony of Company witness Eugene M. Breuring. DR potential from a mandatory time of use rate, like the Summer Peak Rate, was detailed in the AEG Statewide DR Study commissioned by the State of Michigan as a base Time-Of-Use ("TOU") tariff with a 116 MW DR potential by 2019 and 258 MW potential by 2020 (page 55 of report).[1] While the Company does not intend to consider the Summer Peak Rate a DR resource, the tariff is still achieving the objective of shifting load

[1] https://www.michigan.gov/documents/mpsc/State_of_Michigan_-_Demand_Response_Potential_Report_-_Final_29sep2017__602435_7.pdf

away from off-peak times and, as such, will limit the Company's ability to further reduce demand to the levels in the IRP in Case No U-20165.

SECTION IV: DR PILOTS

Q. Have the residential and business pilot costs and projected MW reductions been incorporated into this filing?

A. The Company has requested costs for currently approved and proposed pilots as part of the current electric rate in in Case No. U-20963 and as such are included in the O&M Base Outlook costs in this filing. These are pilot costs only and would not reflect the dollars needed to bring the product to scale. The pilot MW results have yet to be determined through customer participation and, as such, the Company has only included potential MW reductions in the DR glidepath that are identified in its Potential Study. The Potential Study includes a new Small Business DPP Program that would offer a significantly reduced volumetric rate, except on event days when the retail rate increases to approximately $1 per kW during the critical peak window, similar to the residential DPP program that the Company currently offers. The Company will follow the guidelines for pilot implementation as established in Case No. U-20645.

SECTION V: EXECUTION RISKS

Q. Has the Company identified any execution risks associated with implementation of business DR programs within the PCA?

A. Yes. The Company has identified execution risks associated with increasing business DR to the levels identified in the DSA and included in the PSA. These risks primarily result from including smaller to medium sized business customers in the program, driving the average MW reduction per program participant down. The current design of the business

DR Program has fixed cost per participant for license fees, facility set-up costs, and hardware. As the average MW reduction per customer falls, the cost per MW increases. To account for this risk, the Company is not currently providing load monitoring equipment to customers that nominate under 100kW per location. The Company continues to study options to utilize new and/or existing platforms to capture the data from smaller business customers. Additionally, the Company is currently evaluating risks regarding the implementation of the Energy Intensive Primary rate. The intent of the tariff, much like the residential DPP rate, was for MISO based pricing signals during time of an emergency event to be significant enough to lower customer usage. Current MISO market pricing has been lower than previously anticipated during peak hours and the Company is working to understand the impacts on EIP customer load and participation.

Q. Has the Company identified any execution risks associated with implementation of residential DR programs within the PCA?

A. Yes. In addition to the execution risk related to the Summer Peak Rate listed on page 12, lines 16 through 23 of my testimony, the Company has identified that customer acquisition and interactive effects could present risks to increasing residential DR to the levels identified in the in the PCA.

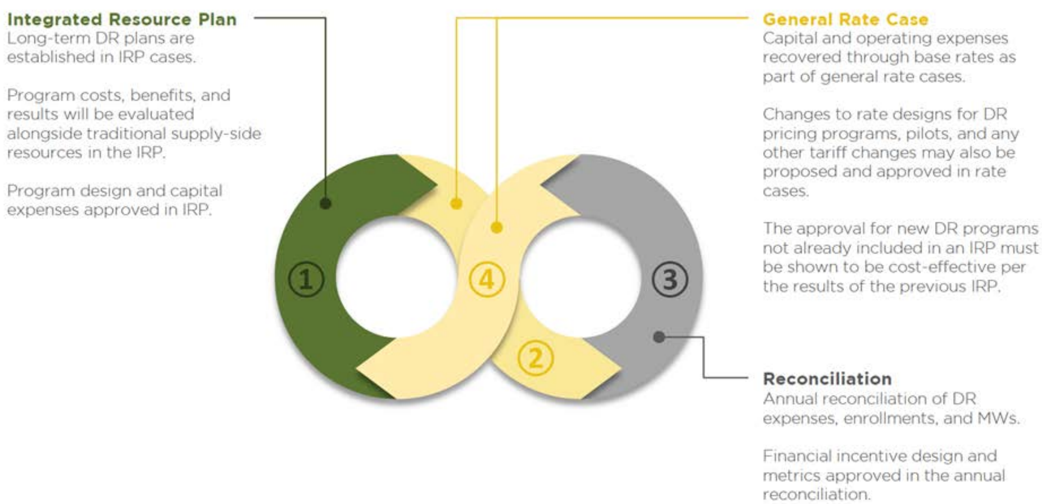
Q. Does the company plan to deliver on the MW targets by program as indicated in Exhibit A-82 (EAM-1)?

A. While the Company intends to deliver on the MW targets in aggregate, it sees the need for flexibility to balance MWs between programs taking into account factors such as product cost and customer demand.

SECTION VI: PERFORMANCE INCENTIVE

Q. Please describe the regulatory framework for DR.

A. In its September 15, 2017 Order in Case No. U-18369 ("September 15 Order"), the Commission established a three-phase approach to addressing DR with: (i) capital costs approved in an IRP considered prudent and reasonable for recovery; (ii) O&M costs reviewed and approved in the general rate case; and (iii) an annual reconciliation proceeding in which actual capital spending will be reconciled with the amount approved in the IRP and recovered in the rate case, while O&M spending will be reconciled against the amount approved and recovered in the general rate case.



Q. Why is a DR performance incentive important for encouraging utility investments in DR programs?

A. As recognized by the Commission in its September 15 Order approving this regulatory framework, having a stable regulatory framework is a necessary condition for implementing the minimum level of DR resources, but it is not a sufficient condition for encouraging utilities to maximize their use of these resources. In its comments on the DR regulatory framework, the Advanced Energy Management Alliance ("AEMA") mentioned the disparity that exists between the necessary and sufficient conditions for encouraging investments in DR resources. AEMA's Comments filed on August 31, 2017, in Case No. U-18369, assert that "...demand-response will not truly be on equal footing with generation, even if there is a comparable consideration in the regulatory process. From a utility's perspective, they are worse off if they invest in a program for which they cannot earn a return than if they invest in a capital project where returns are guaranteed. Given a fiduciary duty to shareholders [investing in demand-response resources] may be an imprudent choice for the utility even if it is the best choice for their customers."[2]

While the Company does consider the cost impact of its actions on customers, it has traditionally used supply-side resources to address increases in customer demand. Indeed, prior to 2017, the Company only had a relatively small amount of DR resources enrolled under its standard interruptible tariff. The Company had focused its efforts on resources that satisfied both its regulatory requirement of providing affordable service to customers and its fiduciary requirement of providing a return on investment to shareholders. But, much like energy efficiency, which was not used by utilities in Michigan until a stable regulatory framework and performance incentive was established under Public Act 295 of 2008, the Commission now has an opportunity to approve a DR performance incentive to promote utility investments in cost effective demand-side resources. Without a performance incentive, the Company would likely not increase its DR portfolio to the levels outlined in the PCA.

[2] September 15 Order, page 10.

Q. Has the Company included the expected performance incentive amount in its projected DR costs in Exhibit A-82 (EAM-1))?

A. Yes. The Company included the impacts of their proposed 20% performance incentive mechanism and included it in the program costs provided to DSA who modeled the cost information in the Consumers Energy Potential Study.

<u>SECTION VII: SUMMARY</u>

Q. Please summarize your direct testimony.

A. As outlined in my direct testimony, the Company has existing and proposed DR programs which are incorporated into the IRP. As such, the Company is requesting that the Commission determine as reasonable and prudent for cost recovery purposes the capital costs that are incremental to those proposed in Case No. U-20693, which are for the time period January 1, 2023 through June 30, 2025.

Q. Does this conclude your direct testimony?

A. Yes.

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 Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))))	Case No. U-21090

DIRECT TESTIMONY

OF

MATTHEW S. HENRY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

Q. Please state your name and business address.

A. My name is Matthew S. Henry, and my business address is 1945 W. Parnall Road, Jackson, Michigan, 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Distribution Automation Technologies Team Lead in the Grid Modernization department.

Q. Please describe your educational background.

A. I earned an Associate's degree in Engineering from Lansing Community College in 2010 and a Bachelor of Science degree in Electrical Engineering from Michigan State University in 2013. I also earned a Master's in Business Administration with a focus in Business Intelligence from Baker College in 2020.

Q. Please describe your work experience.

A. I began my career with Consumers Energy in 2014 as a rotational engineer. In 2016, I began a permanent role in the Grid Modernization department where my responsibilities included serving as the engineering lead on large-scale deployment projects including capacitor controllers and Volt-VAR optimization ("VVO"). I supported the deployment of unmanned aerial vehicles, low voltage distribution ("LVD") supervisory control and data acquisition ("SCADA") systems, and PI Historian software. In 2019 I was promoted to my present position.

Q. What are your responsibilities as the Distribution Automation Technologies Team Lead?

A. My responsibilities include supervising the engineering team responsible for deployment of automation loops, line sensors, voltage regulator controllers, and conservation voltage reduction ("CVR") as well as the research and evaluation of new automation technology. I have continued to serve as the CVR program lead, which includes providing support on the Integrated Resource Plan ("IRP") and Electric Distribution Infrastructure Investment Plan ("EDIIP").

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide an overview and update of the Company's CVR program, detail CVR program deployment and assumption updates, and share and explain the program's pilot deployment results, including costs and benefits. In the section entitled "CVR Program Overview and Strategy," I explain the general concept of CVR and the Company's methodology for implementing and measuring the benefits of the technology. In the section entitled "CVR Program Assumptions," I identify and explain the updates to the CVR program's cost and benefit assumptions. In the section entitled "CVR Results," I provide the costs and benefits observed through the program since its inception. I will also detail key factors that explain variation from original forecasts and summarize the third-party analysis review of our measurement and verification ("M&V") methodology.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-86 (MSH-1) CVR Benefits Forecast;

Exhibit A-87 (MSH-2)	CVR Capital Investment Forecast;
Exhibit A-88 (MSH-3)	CVR O&M Costs Forecast;
Exhibit A-89 (MSH-4)	Cost Approval Request;
Exhibit A-90 (MSH-5)	CVR Benefits;
Exhibit A-91 (MSH-6)	CVR Costs; and
Exhibit A-92 (MSH-7)	CVR Third Party Report.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

<u>Section I: CVR Program Overview and Strategy</u>

Q. Please explain how CVR technology works.

A. CVR is a proven set of technologies that reduces the delivery voltage along electric circuits, then in turn reduces the amount of electric load that must be served on the electric circuit, and thus, on the electric system. The technology works together and optimizes control settings on both substation and downstream voltage regulating equipment. The technology allows for continuous monitoring and automatic adjustment of these settings to achieve optimal voltage and load reduction while staying within the regulatory requirements.

Q. What is the primary objective of CVR?

A. The primary objective of CVR is to reduce energy demand and the associated carbon footprint of the electric system by optimizing service-point voltages without requiring active participation or behind the meter investment by customers.

Q. What is the objective of the CVR pilot?

A. The objective of the CVR pilot is to determine the level of savings that should be expected across the electric system when CVR is enabled. The Company determined that an industry best practice for capturing CVR benefits is through a methodology called "Day-on/Day-off". This means that each of the selected pilot circuits alternate daily between a reduced "CVR-on" voltage output at the substation and a previously utilized, higher "CVR-off" voltage output. In doing this the Company is able to compare the average voltage and load across the day-off days and the day-on days in order to determine energy reduction benefits. The results of this pilot testing will inform the Company of the expected average voltage and load reduction percentages that should be applied to additional CVR-circuits for determining an accurate benefit forecast.

Q. Where has CVR been enabled?

A. CVR has been enabled on the Company's LVD circuits.

Q. Please describe an LVD circuit.

A. The Company's electric distribution system is comprised of two subsystems: High Voltage Distribution ("HVD") and LVD. The HVD system voltage is stepped down, or reduced, at LVD substation transformers onto the LVD system. The LVD system is comprised of over 2,000 LVD circuits, which include primary voltages between 2.4 kV and 24.9 kV. The LVD voltage is then further stepped down at the transformers to a secondary voltage, serving businesses residences at voltages between 120 volts and 480 volts.

Q. When was CVR enabled?

A. The first LVD circuit was enabled with CVR on August 7, 2019. By the end of 2019, a total of 10 circuits were CVR-enabled. The final CVR pilot circuit (#50) was enabled on July 2, 2020.

Q. Has CVR been implemented on circuits beyond the program pilot?

A. Yes, deployment continued beyond the pilot in the second half of 2020. The Company enabled 25 additional circuits beyond the initial 50 in the pilot. For these additional circuits, CVR was no longer enabled in the Day-on/Day-off methodology, but rather in an "Always On" implementation. Circuits 51 and upwards receive reduced CVR-on voltage levels that remain at the reduced level throughout all hours of the day, every day of the year. The data analysis from these circuits does not contribute to the pilot objective; however, these circuits are achieving energy savings towards the CVR program objectives.

Q. Will the CVR program be applied universally across the entire distribution system?

A. No, there will be circuits where economic benefits are insufficient to deploy CVR. For instance, there are circuits with primarily commercial and constant power end-use loads that do not realize the same energy reduction benefits as those of other load type categories. Additionally, there will be circuits that would require a significant amount of investment to attain the capability to reduce voltage and implement CVR. The Company will only deploy CVR on circuits with a reasonable cost-benefit ratio.

Q. How are CVR circuits selected?

A. The CVR program created a circuit candidate pool by filtering the list of every distribution circuit down to only those that should be considered as potentially viable candidates to enable CVR. This filter was primarily based on customer types and circuits with smart grid capabilities. For example, the Grid Modernization program estimates that smart grid equipment will eventually be available on approximately 85% of the LVD circuits; therefore, circuits that are not cost-effective for distribution SCADA ("DSCADA") deployment are ruled out from CVR consideration. Additionally, circuits that have primarily industrial and commercial customers were removed. The principal reason for this is that industry analysis has shown that CVR is more effective on residential load types. From within this circuit candidate pool, the initial 50 pilot circuits were selected to be a representative sample of the population. Multiple factors were considered for this initial selection including, but not limited to, customer type (residential/commercial/industrial), circuit design characteristics, geographic region, circuit length, and voltage class. Priority was given to customer type, while ensuring that each of the other categories were not under-represented or over-represented. Circuits enabled beyond the initial pilot were selected based on those that had lower anticipated costs. For example, circuits that have already deployed the necessary upgrades to substation and line equipment were prioritized. Additionally, circuits where less capital investments would be required, as determined by a power flow study, were prioritized. Moving forward, once the data analysis from the pilot phase is complete, the Company will begin prioritizing circuits that have an acceptable CVR cost-benefit ratios. For example, specific customer breakdowns or circuit characteristics may be prioritized to maximize investments and benefits.

Q. How long will the CVR pilot run?

A. The Company originally planned to run each pilot circuit for 365 consecutive days of alternating on and off days. However, due to unexpected interruptions of CVR enablement, the Company determined that the pilot should be extended through September 30, 2021, to capture a full year of data. These interruptions included an Advanced Distribution Management System ("ADMS") upgrade in November 2020, load transfers, and delays stemming from COVID-19 impacts. Another contributing factor in the decision to implement a pilot extension was due to unanticipated and unusual load behavior stemming from COVID-19 impacts. Many circuits experienced load behavior impacts throughout mid-2020 that was outside of the normal behavior. Residential load was higher than normal levels, while industrial and commercial load was lower than normal levels, likely due to COVID-19 related policies. The CVR project team determined that an additional summer of load monitoring will serve two beneficial purposes; the Company will be able to determine a baseline for normal circuit behavior with additional data, and the Company will be able to capture outlier behavior from 2020 that resulted from COVID-19 impacts to more accurately predict future CVR performance.

Q. Will a pilot extension impact the deployment plan?

A. No, the Company will continue to enable additional CVR circuits in the "Always On" mode while CVR pilot analysis is being finalized.

Q. Does CVR include multiple implementation objectives?

A. Yes, the Company has dispatched CVR with two separate objectives. The first objective serves an energy waste reduction ("EWR") goal of lowering energy usage year-round through voltage and load reduction. This every day, year-round voltage reduction reduces end-load usage throughout every season, at all hours of the day. The second CVR program objective serves a demand reduction ("DR") goal of reducing peak system load for a few hours at a time during the summer cooling season. This implementation of CVR consists of additional voltage reduction to shave peak demand on the highest loading days of the summer months.

Q. How does CVR implementation differ between the DR and EWR objectives?

A. When CVR is utilized for the DR objective, the average voltage reduction target is 5%, double that of the EWR target of 2.5%. The company can accomplish this goal because typical CVR reduction levels observe a reserve margin between the lowest metered customer voltage and the minimum voltage threshold. This cushion is intentional and necessary for year-round CVR operation to prevent frequent deviations below the low voltage threshold. For CVR during the DR objective, the goal is to approach but not surpass the low voltage threshold for a few hours and only on peak load days.

Q. Did the Company implement CVR for the Demand Reduction objective in 2020?

A. Yes, 2020 served as a pilot year for CVR's DR implementation. The goal of the DR pilot was to document and execute the steps necessary for lowering voltage by an average of 5% at specific high load intervals. The Company also developed tools and processes to allow for improved monitoring and execution of CVR as a dispatchable DR asset. In total the Company executed twelve days of CVR DR events spread across twenty-two different circuits. Additionally, CVR-enabled circuits that were not involved in a peak DR event also observed peak shaving benefits from the normal 2.5% voltage reduction.

Q. How does the Company measure CVR DR Benefits?

A. The Company will measure DR benefits using an analytic tool called MetrixND which creates a predicted load profile utilizing historical voltage, load, calendar, and temperature data. The analytic tool creates a load model prediction over a defined interval that forecasts what would have happened had a DR event not been implemented. Savings are determined by analyzing the difference between the predicted and actual load measurements from each DR event. This is the same tool used by the Company for other DR programs to measure benefits of load reduction events.

Q. How does the Company measure CVR EWR Benefits?

A. The Company measures EWR benefits by comparing the average voltage and load data from the day-off days to the same averages from the day-on days. Comparing any single day to one other day may not provide a clear picture of benefits; however, by providing the average over a longer span of time, the average load reduction benefits of CVR implementation can be observed. Once the Day-on/Day-off pilot data analysis is complete, the Company will apply the calculated average savings to all of the CVR-enabled circuits to determine benefits.

Q. Do energy savings vary based on end-use loads?

A. Yes, certain end-use loads may not observe energy savings, particularly constant energy devices that increase current draw in response to reduced voltage, or devices that are set to meet certain objectives such as water temperature in a hot water heater or indoor temperature for an air conditioner. However, all other end-use loads will produce energy savings in response to CVR operations. Therefore, from a system perspective, there will be energy savings.

Q. What is the appropriate voltage level for electric service on the LVD system?

A. The Company regulates voltage on its LVD system in accordance with established standards such as American National Standards Institute ("ANSI") Standard C84.1 and MPSC Standard R 460.3702 Rule 702. MPSC Rule 702 states "the variations of voltage shall be not more than 5% above or below the standard nominal voltage" except as noted in subrule (4) which states "Voltages outside the limits specified in this rule shall not be considered a violation if the variations are infrequent fluctuations or occur from adverse weather conditions, service interruptions, causes beyond the control of the utility, or voltage reductions that are required to reduce system load at times of supply deficiency or loss of supply". Many electric devices are designed to operate at a voltage between 110-127 volts in order to perform satisfactorily. ANSI C84.1 Range B allows an operating range of 106-127 volts, however such conditions should be "limited in extent, duration, and frequency, and reserved for emergency conditions".

Q. How does the CVR program ensure that customers on CVR circuits receive acceptable voltage?

A. The CVR program utilizes daily monitoring of voltage readings for customers on CVR-enabled circuits. Voltage readings are stored in a database and, if low voltage deviations are found to violate the aforementioned standard, they are investigated and mitigated through either an increase to CVR voltage set points or via a remediation design to boost secondary voltage.

Q. Does this program require customer opt-in or action?

A. Unlike other load reduction or energy efficiency initiatives, CVR does not require an opt-in or customer enrollment. CVR obtains results in end use reduction without customer interaction. Additionally, this reduction in voltage has no adverse effect on customer service.

Q. Are there other ongoing Grid Modernization initiatives that impact the CVR program?

A. Yes, other Grid Modernization initiatives play a key role in enabling CVR on the LVD system. Specifically, the DSCADA and the regulator controller upgrade projects are pre-requisites for the enablement of CVR. These projects consist of adding communication equipment to field devices which provides real-time data monitoring and control to the LVD system.

Q. Are these supporting Grid Modernization initiatives on track to sustain the CVR deployment plan?

A. Yes, both the DSCADA and regulator controller deployments have continued upgrading and enabling communication equipment as scheduled to align with CVR enablement objectives.

Section II: <u>CVR Program Assumptions</u>

Q. Please explain Exhibit A-86 (MSH-1).

A. Exhibit A-86 (MSH-1) presents the new and cumulative circuit deployment, forecasted megawatt ("MW") reduction, and forecasted megawatt-hour ("MWh") reduction, which consists of both VVO and CVR contributions, from the years 2021 through 2040. As shown in the exhibit, the CVR program is expected to reduce annual electric demand by 113 MW and 272 gigawatt-hours ("GWh") by the year 2030. Column c presents the cumulative total of CVR-enabled circuits deployed. The Company forecasts the enablement of 85 circuits per year through 2029 and 60 in the final deployment year 2030, to reach a total of 900 circuits across the system. Column e presents the cumulative forecast for MW demand reduction benefits. Column k presents the cumulative forecast for MWh energy reduction benefits.

Q. Please explain Exhibit A-87 (MSH-2).

A. Exhibit A-87 (MSH-2) presents CVR circuit deployment and the annual projected capital investments for the CVR program from the years 2021 through 2040. Capital investment is forecasted to wrap up in 2030 with the completion of circuit deployment. Column d shows costs for labor, column e shows costs for circuit conditioning, column f shows total capital investment, and column g shows costs for a shared savings incentive.

Q. What are the primary components of the capital investment?

A. The primary components are CVR labor and circuit conditioning. CVR labor consists of salaries for engineers, analysts, and SCADA support. Capital circuit conditioning consists of both Grid Modernization upgrades, specifically the deployment of DSCADA and voltage improvement line devices (such as regulators, capacitors, and VAR compensators), and the upgrades of transformers and secondary services. These capital investments are a prerequisite for enabling CVR and are essential in order to prepare the system for voltage reduction.

Q. Is the Company considering new voltage improvement technologies to improve CVR performance?

A. Yes, in addition to the standard voltage regulator and capacitor upgrades, the Company is also looking into new line devices which can improve CVR performance. The first technology is a more resilient capacitor bank assembly that includes vacuum-interrupting switching technology and heavy-duty capacitor cans. In 2021, the Company plans to dedicate a portion of the voltage improvement costs to go towards testing and deployment of the more resilient capacitor assemblies on a small scale. Data analysis will be conducted to determine the anticipated cost-benefit ratio of utilizing the upgraded capacitor assembly. The second technology the Company is considering is static VAR compensators ("SVC"). These SVC devices are electronic secondary capacitors that will provide fast, variable voltage support to help stabilize and regulate the voltage. These devices will be a new technology introduced to the Company's distribution system. Each device will be able to act in less than a cycle, as opposed to a traditional capacitor device that operates on time delays, typically of five minutes. These devices will provide dynamic voltage response and will be located closer to customers which are located near the edge of the electric grid. In 2021, the Company plans to dedicate a portion of the voltage improvement costs to strategically test and deploy approximately 20 Edge of Network Grid Optimizers ("ENGO"), a specific type of SVC, to provide additional voltage support. These devices have previously been deployed for CVR solutions by peer utilities such as Xcel Energy, Hawaiian Electric, and Southern Company.

Q. What are the benefits associated with the new voltage improvement technology?

A. The capacitor improvements are aimed to reduce the rate of capacitor failure, resulting in an increased lifespan of capacitor equipment and a corresponding reduction of Operating and Maintenance ("O&M") costs. SVC devices will benefit CVR by providing edge-of-grid voltage support for improving power quality. This enables the company to achieve additional voltage reduction, resulting in increased energy savings. Additionally, the SVC device capabilities will enhance the system's ability to respond to the variability of renewable distributed energy resources ("DER"), such as solar.

Q. Please explain Exhibit A-88 (MSH-3).

A. Exhibit A-88 (MSH-3) presents CVR circuit deployment and the annual projected O&M expenses for the CVR program from the years 2021 through 2040. Column d shows costs for labor and column e shows costs for circuit conditioning.

Q. What are the primary components of the O&M costs?

A. The primary components are CVR labor and circuit conditioning. CVR labor consists of salaries for engineers, analysts, and SCADA support. O&M circuit conditioning primarily consists of monitoring and maintenance of electric infrastructure, such as capacitors, regulators, and transformers, and the associated smart grid equipment. LVD equipment must be fully functional in order for CVR benefits to be realized.

Q. Are there learnings from the pilot that have improved the CVR program's forecast model and assumptions that were developed in 2018?

A. Yes, through CVR pilot deployment learnings, several program assumptions were updated to improve the accuracy of cost and benefit forecasting. These assumption updates include an update to the number of circuits on the LVD system, an increase to the forecasted CVR circuit penetration, an update to the deployment schedule to align with the 2018 IRP settlement and project start, and an update to the system load forecast. These assumption changes are described in detail below.

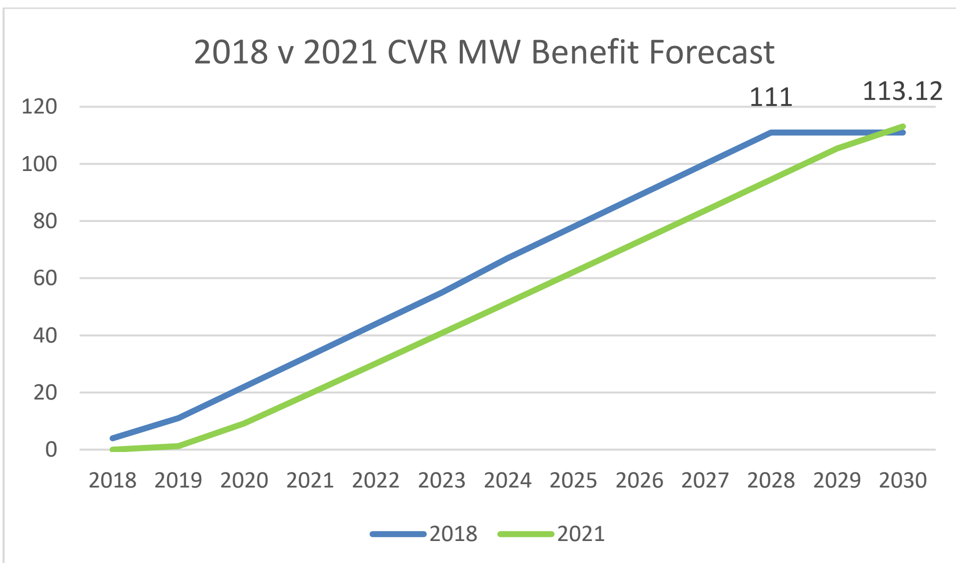
Q. What was the net impact of the assumption changes to the overall CVR cost forecast?

A. The assumption updates led to an increase in the overall program's forecasted capital circuit conditioning spend from a total of $25,000,000 to $35,000,000. The main contributor to the increase in costs is the increase to the number of circuits in the deployment plan. This increase in total circuits deployed from 500 to 900 resulted in an increase to the amount of circuit conditioning and capital upgrades required to deploy CVR.

Q. What was the net impact of the assumption changes to the overall CVR benefit forecast?

A. The assumption updates led to an increase in overall program forecasted MW reduction from 111 MW to 113 MW and the forecasted MWh reduction from 265,000 MWh to 272,000 MWh. The main contributors to the change in benefit forecast was the update to the count of LVD circuits and the increased circuit deployment. The CVR model was updated so that it included not just the LVD circuits that exist within the CVR candidate pool, but instead the entire system. The CVR model's increased circuit count from 1,800 to 2,244 reduced the generation load that was attributed to the average circuit. As a result, each individual circuit's forecasted load reduction impact was decreased. The lower average load per circuit paired with an increase in total circuits deployed resulted in a net impact of a 2% increase in total MW and MWh reduction benefits. Figure 1 shows the variance between the original and the current MW benefit forecast.

Figure 1



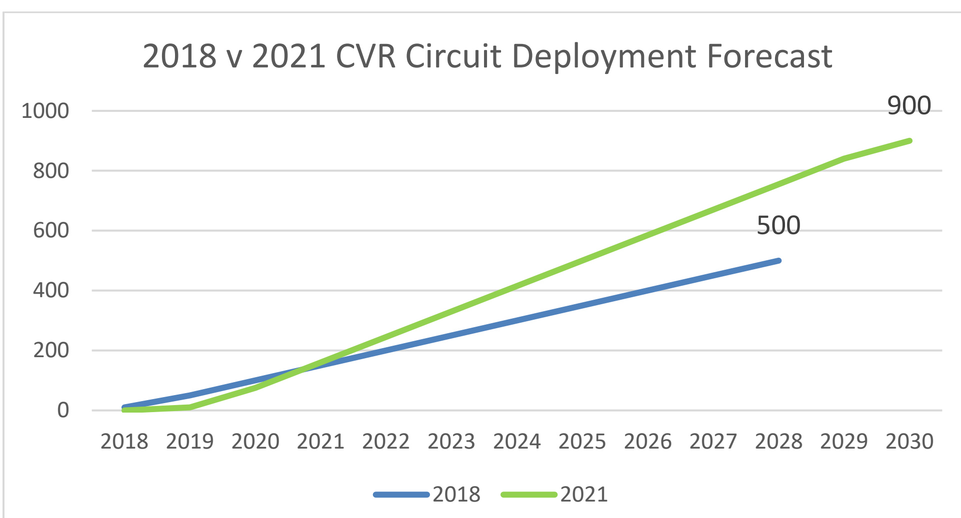
Q. What factors led to the increase in CVR circuit deployment?

A. Based on the pilot learnings, the Company was able to better understand and validate circuit characteristics that should be targeted for CVR enablement. As a result, the Company has determined that more circuits can be enabled in the potential pool of CVR candidates. The increase in CVR circuits is supported by the Company's CVR pilot analysis. CVR capability analysis consists of two main steps, conducting a power flow study to determine the anticipated level of voltage reduction capability, and monitoring historical advanced metering infrastructure ("AMI") customer voltage data. The result of this analysis on hundreds of individual circuits revealed that a higher percentage of circuit candidates would be capable of CVR enablement.

Q. Did the CVR deployment plan change?

A. Yes, the CVR circuit deployment change was based on the 2018 IRP settlement being completed in June 2019. This shifted the program start to mid-2019, from early 2018 as originally forecasted. From the 2019 program launch, the program's deployment plan was accelerated to meet the original forecast in a shorter timeframe. This acceleration allowed the Company to get closer to the original forecast despite the delay. Figure 2 presents a graph of the original and current forecast for CVR circuit deployment. The Company increased the second-year planned deployment from 30 circuits to 65 circuits and increased the third-year and beyond annual deployments from 50 circuits per year to 85 circuits per year. These changes will bring the total number of CVR-enabled circuits at full deployment from 500 to 900 while extending the deployment end date from 2028 to 2030.

Figure 2



Q. Did the CVR program update its load forecast to align with the Company's updated load forecast?

A. Yes, the CVR program used the Company's updated load forecast in CVR benefit modeling. The Company's load forecast observed a slight decrease to the annual generation load which contributed to a slightly lower load reduction capability for the average CVR circuit.

Q. With the assumption updates, does the CVR program remain a cost-effective program?

A. Yes, the CVR program continues to be an enormously beneficial program. This is validated in Company witness Sara T. Walz testimony, which reveals that CVR is a low cost, high benefit program.

Q. Is the Company requesting pre-approval of CVR costs associated with the forecasted demand reduction and energy waste reduction savings?

A. Yes, the Company is requesting pre-approval for capital and O&M costs for CVR from January 1, 2023 to June 30, 2025 as shown in Exhibit A-89 (MSH-4).

Section III: CVR Results

Q. Please explain Exhibit A-90 (MSH-5).

A. Exhibit A-90 (MSH-5) presents the energy reduction and peak demand reduction benefits observed by the program from August 7, 2019 through December 31, 2020. As seen in the exhibit, columns a through f list the 75 CVR-enabled circuits with details including CVR ID#, Feeder ID, Headquarter ("HQ"), Substation, Circuit, and Enablement Date. Column g shows the total number of hours that CVR was enabled at a reduced voltage level. Columns h-m show the average voltage and load measurements and the percent reduction from CVR-off to CVR-on days. Column n shows the CVR factor ("CVRf") a metric used to measure CVR performance which is described in more detail later in this testimony. Columns o-r show the calculated actual and the forecasted annual energy savings and peak demand load reductions. Column o's calculated energy savings represents the amount of load reduction observed as a result of CVR operation. Column n's forecasted energy savings represents the annual savings capability that CVR has provided. This forecast represents the amount of savings that should be expected for each circuit annually once the pilot is complete. While a circuit is in the pilot phase and undergoing Day-on/Day-off implementation, it will measure actual savings of only half of what is possible had it been on for a full calendar year. Calculated demand reduction in column q represents the peak load value that was reduced during 2020 summer. Column r's forecasted demand reduction represents the reduced load that should be expected based on the circuit's 3-year historical average peak load. Column s shows the percentage of AMI measurements during CVR enablement that fell within the ANSI standard's Range A of 5% above or below the standard nominal voltage. Columns t through v show the average customer voltage across CVR-off and CVR-on days as well as the voltage reduction percentage. Column w lists the number of customers that are connected to each circuit. Finally, column x represents the total number of AMI voltage measurements that the CVR program has observed as a part of CVR operation.

Q. What was the energy savings benefit measured from the CVR program through 2020?

A. As seen in column o the total energy savings measured across the 75 CVR-enabled circuits was over 5.6 GWh. Column n reveals that annual savings of 21.2 GWh are expected across the 75 circuits once the Day-on/Day-off pilot is complete.

Q. What was the peak demand reduction benefit measured from the CVR program through 2020?

A. As seen in column q, the Company observed a 5.65 MW reduction in 2020 across the 75 CVR-enabled circuits. As seen in column r, based on the historical 3-year average peak loads, the peak demand reduction that should be expected from the 75 enabled circuits is 10.67 MW.

Q. Are there other indirect benefits from load reduction?

A. Yes. Load reduction can mitigate overloading of utility equipment and reduce operation of devices, extending equipment life. This allows for either the avoidance or deferment of higher cost capacity upgrades in substations and on the LVD lines. Additionally, as customers' energy consumption grows more dynamic with DER, batteries, electric vehicles, smart appliances, and many more electronic devices, voltage control and optimization will grow in importance. A system that can dynamically react to changes in conditions on the distribution system is necessary to improve the Company's ability to monitor and control voltage levels based on the actual conditions of a circuit.

Q. What factors led to a variance between original forecasts and actual load reduction benefits?

A. The major contributor to the variance in benefits was due to the 2018 IRP settlement date and program start. The original forecast modeled the CVR program to begin in January 2018, however it did not actually launch until August 2019. This delay paired with the reduced load impact per CVR circuit described in Section II explain the key factors in the benefit variance.

Q. What is CVR factor and why is it a valuable metric for reporting CVR performance?

A. CVRf is a metric that is commonly utilized in the industry for reporting CVR performance. This factor is the ratio of the average load reduction to the average voltage reduction.

$$CVRf = \frac{Average\ Load\ Reduction}{Average\ Voltage\ Reduction}$$

The CVRf value represents the percentage of load that would be reduced for every 1% voltage reduced. This metric is a valuable measure to determine how effective a circuit will perform across various categories such as season.

Q. What was the average CVRf observed by CVR pilot circuits?

A. The Company observed an average CVRf across the pilot circuits of 0.82. This average is above the Company's original forecast assumption of 0.80. This figure reveals that on the average CVR circuit, for every 1% voltage reduced, load will be reduced by 0.82%.

Q. What was the average voltage reduction observed by CVR circuits?

A. The Company observed an average voltage reduction of 2.32% across CVR circuits. The range of CVR circuit's voltage reduction varied from 1.63% - 3.07%. The Company is encouraged by the voltage reduction results as it represents the average over the initial launch and early stage of the program when voltage was lowered conservatively. As the

Company gains experience and maturity in voltage reduction optimization techniques, it is confident that the voltage reduction percentage will continue to increase.

Q. Are there factors that lead to extended periods of CVR disablement?

A. Yes. CVR circuits have been disabled for a variety of reasons. One of the most common events that require CVR disablement are temporary circuit reconfigurations, also known as load transfers. During a load transfer, a CVR circuit that picks up additional load from another circuit has CVR disabled. For long-term load transfers, the Company will conduct a power flow study to determine an acceptable voltage reduction to allow for CVR re-enablement without creating low voltage violations. CVR circuits may also be disabled for equipment issues, for example CVR is disabled during substation maintenance or equipment replacement. Another example of an event that led to an extended disablement was the upgrade of the Company's LVD SCADA software system as a part of the ADMS deployment.

Q. How does the Company ensure it eliminates skewed data results from temperature variance?

A. The Company uses a technique it has named "Matching Pairs". This technique matches each day-on day to a corresponding day-off day so that there are an equal number of weekdays and weekends within each season. The Matching Pairs technique excludes standalone days or consecutive day-on or day-off days so that each day has a paired opposite. By doing this the Company avoids scenarios where there are extended weeks of day-off days which can skew results.

Q. Has the Company been able to maintain customer voltages within the allowable threshold?

A. Yes, as seen in Exhibit A-90 (MSH-5) column s, greater than 99.7% of AMI customer voltage reads in the CVR program fall within the allowable voltage range.

Q. Has the Company observed an impact to the quantity of voltage complaints or voltage issues resulting from the CVR program?

A. No.

Q. Please explain Exhibit A-91 (MSH-6)?

A. Exhibit A-91 presents the capital and O&M costs incurred by the program from August 7, 2019 through December 31, 2020. Costs are broken down into 5 main categories: Capital Circuit Conditioning, Voltage Device Upgrades, DSCADA Deployment, Other Capital Costs, and O&M Circuit Conditioning. As shown in the exhibit, the CVR program invested over $1.9M in capital in 2020.

Q. Please describe the Capital Circuit Conditioning category.

A. CVR capital circuit conditioning commonly consists of upgrading transformers, splitting load across multiple transformers, or upgrading secondary conductor. These costs are necessary to ensure customers receive adequate voltage when CVR is enabled.

Q. Please describe the Voltage Device Upgrades category.

A. Voltage device upgrades include costs for regulator controller upgrades which enable remote communication to line regulators. The CVR program funds regulator locations to prioritize those that will be beneficial to CVR but may not be prioritized through other Grid Modernization programs. Capacitor pole top upgrades and repairs are also considered voltage device upgrades. Regulators and capacitors are both required to be fully functional and remote-capable in order to enable voltage optimization and CVR. Another component of voltage device upgrades is the deployment of SVCs which provide voltage improvement at the edge of the grid.

Q. Please describe the DSCADA Deployment category.

A. DSCADA deployment consists of deploying communication equipment to distribution substations which provides remote monitoring and control. This is a required component of CVR enablement. The CVR program funds specific DSCADA additions at substations to prioritize those locations that will be beneficial to the CVR program but may not be prioritized through other Grid Modernization programs.

Q. Please describe the Other Capital Costs category.

A. This category consists of mischarges that were erroneously assigned to the CVR program. This can happen when Company employees enter a typo in the work order management system and charge time and/or resources to the incorrect project. Moving forward the CVR program has implemented monitoring tools for these instances to ensure that these types of costs are corrected prior to year-end closeout.

Q. What is the primary reason for no dedicated O&M spend in 2020?

A. O&M costs are primarily driven by circuit conditioning. With only 10 circuits deployed prior to 2020, there was no maintenance required on the small number of circuits in 2020. As more circuits are enabled, for longer durations, maintenance will be required to keep circuits and their devices operating functionally.

Q. Has the Company completed annual reporting regarding CVR capital investment and benefits pursuant to the settlement outlined in the Company's 2018 IRP case number U-20165?

A. Yes, beginning in 2020 and continuing in 2021, the Company has submitted annual reports which outline the previous years' cost and benefit figures. These annual reports provide a narrative of the CVR program's annual costs, benefits, and variation descriptions.

Q. Has the Company engaged a third-party to verify that the Company's measurement and verification methodology is in line with industry standards?

A. Yes, the Company began an engagement with ESTA International on March 1, 2021 to assess the Company's CVR program implementation and benefit methodology. The engagement was conducted over twelve weeks and consisted of two main objectives. First, ESTA reviewed and evaluated the methods used by the Company to conduct the Day-on/Day-off CVR pilot and to assess the methodology used to analyze the resulting data to determine the CVRf performance metrics. The proposal includes an assessment of the following items: process used for selection of circuits, CVR software algorithms, controlled devices, data collected during the demonstrations, and method of computing CVRf for peak demand and energy consumption. The second objective was to develop a mechanism for predicting CVRf on non-CVR circuits. The goal of this activity was to apply calculated CVR data to develop a methodology for predicting the CVRf of a given circuit before adding CVR capabilities. This deliverable will help the Company identify circuits with the highest benefits for greater utilization and efficiency in deployment. ESTA provided a summary report of the first objective in May, which is my Exhibit A-92 (MSH-7).

Q. Describe the third-party reviewer's qualifications to assess the Company's CVR program metrics and benefits.

A. ESTA has recently completed a detailed M&V assessment of CVR for Consolidated Edison of New York and has also conducted similar assessments for other utility companies. ESTA's team lead, Mr. Robert Uluski, has served as Chair of the IEEE PES Task Force on Volt-VAR control and optimization and played a lead role in developing IEEE Standard 1885: "Guide for Assessing, Measuring and Verifying Volt-VAR Control Optimization on Distribution Systems" which identifies ways in which electric distribution utilities have evaluated the CVR benefits. This standard was recently approved and published by IEEE. Mr. Uluski has also managed EPRI's "Smart Distribution" research program that included extensive work in laboratory testing to identify load-voltage sensitivity of major electrical appliances and equipment and in load-voltage modelling. ESTA's Bob Uluski served as the Executive consultant on the project. Mr. Uluski has 40+ years of electric utility experience and is an industry expert in CVR M&V practice.

Q. What were the key takeaways from the third-party review?

A. The key takeaway from the third-party review was that the results obtained from the Company's pilot analysis are valid and that it is reasonable to assume similar results will be obtained from additional circuits as CVR is enabled. In ESTA's opinion, the selected CVR circuits are representative of the CVR proposed set of circuits, and the circuit selection process used by the Company was considered far more detailed and superior to the selection process used by other utility companies. Additionally, the Company's CVR methodology, controlled devices, software algorithms, and the data collected are consistent with industry best practices.

Q. Did the third-party evaluator validate Company's calculated benefits and the benefit calculation methodology?

A. Yes, ESTA concluded that the results obtained by the Company during its CVR demonstration and analysis are valid and representative of results than can be expected when implementing CVR on additional circuits. ESTA concluded that the Company's methodology is relatively easy to understand and implement, as compared to other advanced techniques such as regression analysis and neural network modeling.

Q. Does this conclude your testimony?

A. Yes.

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 Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))))	Case No. U-21090

DIRECT TESTIMONY

OF

EUGÈNE M.J.A. BREURING

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

Q. Please state your name and business address.

A. My name is Eugène M.J.A. Breuring, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Senior Rate Analyst III in the Planning, Budgeting and Analysis Section of the Rates and Regulation and Quality Department.

Q. Please describe your educational background and employment experience.

A. In 1992, I graduated from Grand Valley State University with a Bachelor of Business Administration degree in Accounting. In 1996, I graduated from Thunderbird School of Global Management with a Master of Business Administration degree in International Management. I have also attended trade-specific conferences and seminars related to Michigan and United States economies, Michigan economic forecasts, as well as regression modeling.

Prior to joining Consumers Energy in 2013, I worked at the Kellogg Company, Tecumseh Products Company, and Stryker Corporation, mostly in a financial planning, budgeting, and forecasting capacity. In January of 2013, I accepted the position of Senior Rate Analyst II. In 2020, I was promoted to Senior Analyst III, which is my current position at Consumers Energy. In this capacity, I am responsible for preparing the Company's official electric sales and customer forecasts, sponsoring the sales and customer forecast testimony and exhibits, industry research, and various economic studies. Also, I am responsible for creating the Company's revenue forecast related to the electric businesses.

Q. Have you sponsored testimony in any previous cases before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I have presented the Company's electric business sales and revenues forecasts in the following cases:

U-17771	2016 – 2017 Energy Optimization Plan and 2017 Amended Energy Waste Reduction ("EWR") Plan;
U-17990	General Electric Rate Case;
U-18142	2017 Power Supply Cost Recovery ("PSCR") Plan;
U-18231	2017 Biennial Renewable Energy Plan;
U-18261	EWR Plan;
U-18322	General Electric Rate Case;
U-18402	2018 PSCR Plan;
U-20134	General Electric Rate Case;
U-20165	2018 Integrated Resource Plan ("IRP");
U-20219	2019 PSCR Plan;
U-20372	2019 EWR Electric and Gas Biennial Plan;
U-20525	2020 PSCR Plan;
U-20697	General Electric Rate Case;
U-20802	2021 PSCR Plan; and
U-20875	2021 EWR Electric and Gas Biennial Plan.

Furthermore, I have been involved, in a support capacity, in preparing the forecasts sponsored by other Company witnesses in prior cases before the MPSC.

Q. Please explain the purpose of your direct testimony in this proceeding.

A. The purpose of my testimony is to present the Company's historical annual electric deliveries and monthly peak demands, as well as the Company's forecasted electric deliveries, generation requirements, and peak demands for the period 2021 to 2040.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-93 (EMB-1)	Historical & Forecasted Annual Electric Deliveries;
Exhibit A-94 (EMB-2)	Historical & Forecasted Monthly Peak Demands;
Exhibit A-95 (EMB-3)	Electric Bundled Peak Demand Forecast Sensitivities; and
Exhibit A-96 (EMB-4)	Electric Bundled Generation Requirements Sensitivities.

Q. Were these exhibits prepared by you or under your direct supervision?

A. Yes.

SECTION I: KEY ELECTRIC DELIVERY AND DEMAND VARIABLES

Q. What are the key variables that affect the electric deliveries and demand forecasts?

A. The key variables affecting the forecasts are weather, the economy, and population demographics.

Q. Please describe the impact of weather on the forecasting process and the assumptions you made regarding weather variables in the forecast.

A. Weather is the primary variable used in the forecasting models to capture the seasonal variation in deliveries and demand across the year. This is accomplished using a 15-year average of Heating Degree Days ("HDD") and Cooling Degree Days ("CDD") in the econometric models.

Q. What are econometric models or econometric techniques?

A. These are quantitative economic statistical techniques or tools that model the economy using mathematical and statistical relationships. A basic tool for econometrics is the regression model, as will be discussed below.

Q. Please describe the impact of the economy on the forecasting process and the assumptions you made regarding these variables in the forecast.

A. The Company uses economic indicators to capture the growth expectations related to increased economic activity in its service territory. Primarily, this includes employment and industrial production forecasts provided by IHS Markit, a leading publishing company that provides industry-specific data and analyses.

Q. Please describe the impact of demographics on the forecasting process.

A. Population projections are used in the development of the long-term customer forecast. In particular, the forecast of residential customers is derived from the county-level population projections provided by IHS Markit.

SECTION II: FORECASTING METHODOLOGY

Q. What is forecasting?

A. Forecasting is predicting the future values of data. For purposes of this testimony, I will be forecasting electric deliveries and forecasting peak demand for the Company's electric service territory.

Q. Are there different types of analyses used in preparing forecasts?

A. Yes.

Q. What type of analysis was utilized for forecasting electric deliveries and forecasting peak demand for the Company's electric service territory?

A. I used statistical modeling, or a regression analysis to forecast electric deliveries and peak demand for the Company's electric service territory.

Q. Please briefly describe the process used to prepare the electric deliveries and peak demand forecasts.

A. The electric deliveries and peak demand forecasts are prepared using a combination of econometric and end-use techniques.

Q. What process is involved in developing the electric deliveries forecast?

A. Typically, a six-step process is used in developing the electric deliveries forecast. The first step in the process is gathering the customer class-level historical monthly electric delivery, monthly customer counts, monthly number of billing days, monthly binaries to account for temporal cycles, and daily temperature information. Most observations are entered directly into the modeling framework as dependent and explanatory variables. The daily temperature information, however, is transformed to monthly HDD and CDD variables prior to entering the modeling framework. The second step is importing the economic and demographic variables from IHS Markit into the sales modeling framework. The third step is importing electric use forecasts for wholesale, electric vehicles ("EVs"), polycrystalline production, and energy savings from the Company's EWR programs. These forecasts are exogenous to the modeling framework and were either adopted by the Commission in prior electric rate cases, reflect current industry expectations, or are based on end-use analyses. The fourth step is reviewing the imported observations to identify data issues before running the econometric models. In situations when erroneous data is observed, it is either corrected where possible or removed from the models. The fifth step is executing the regression functions and reviewing the corresponding statistical metrics. The final step in the sales forecasting process is to combine the regression forecasts with the external forecasts imported in step three.

Q. What is the process involved in developing the electric peak demand forecast?

A. The peak demand forecast process is similar to that of the electric delivery forecast. The first step in the peak demand forecast is importing the Company's monthly system peak demands, corresponding minimum and maximum daily temperature, forecasted base electric deliveries, seasonal binaries, and number of customers into the demand modeling framework. A weighted sum of the minimum and maximum temperatures is used to develop the peak CDD and HDD variables prior to importing into the model framework. The second step is reviewing the imported observations to identify data issues before executing the peak demand econometric model. The third step is regressing the observed peak demands against the seasonal binary, degree day, and forecasted base electric sales. The final step in the peak demand forecasting process is combining the results of the econometric model with the Company's projected peak demand adjustments, which consist of: (1) EWR; (2) Conservation Voltage Reduction ("CVR"); (3) Dynamic Peak Pricing ("DPP") programs; and (4) Residential Summer On-Peak rate ("RSP").

Q. In utilizing the regression models, what evaluation process is followed to ensure that the models' results are satisfactory?

A. Regression modeling is used to develop the electric deliveries and customer count forecast models based on weather and economic variables. Each model is selected based on its ability to properly explain variation in historical data – i.e., how well it fits the data – along with the statistical significance of the model coefficients. Particularly, regression model performance is evaluated based on the adjusted coefficient of multiple determination ("R_a^2") and Mean Absolute Percent Error ("MAPE").

Q. Please explain the use of R_a^2 and MAPE.

A. Both of these statistical tests are used to evaluate how well the models fit the historical data, and also provide a good indication of how well the models will perform in the forecast period. The R_a^2 measures the ability of the models to explain variations in the historical data. An R_a^2 of unity suggests that a model explains all of the variations in the data whereas an R_a^2 of zero suggests it explains none of the variations. For example, if regression models have R_a^2 values above 0.9, this suggests that at least 90% of the variation in the data is explained by the models. In most cases, the models used in the Company's forecasting process have values between 0.90 and 0.97. In addition, to gauge overall model performance, the MAPE values are considered. Essentially, the MAPE is used to measure the model errors in which smaller values suggest better model performance. MAPE values between 5% and 10% are generally considered ideal, although higher values may also be deemed acceptable based on other considerations, such as the R_a^2. The regression models used in the Company's forecasting process generally have MAPE values between 0.2% and 2.1%.

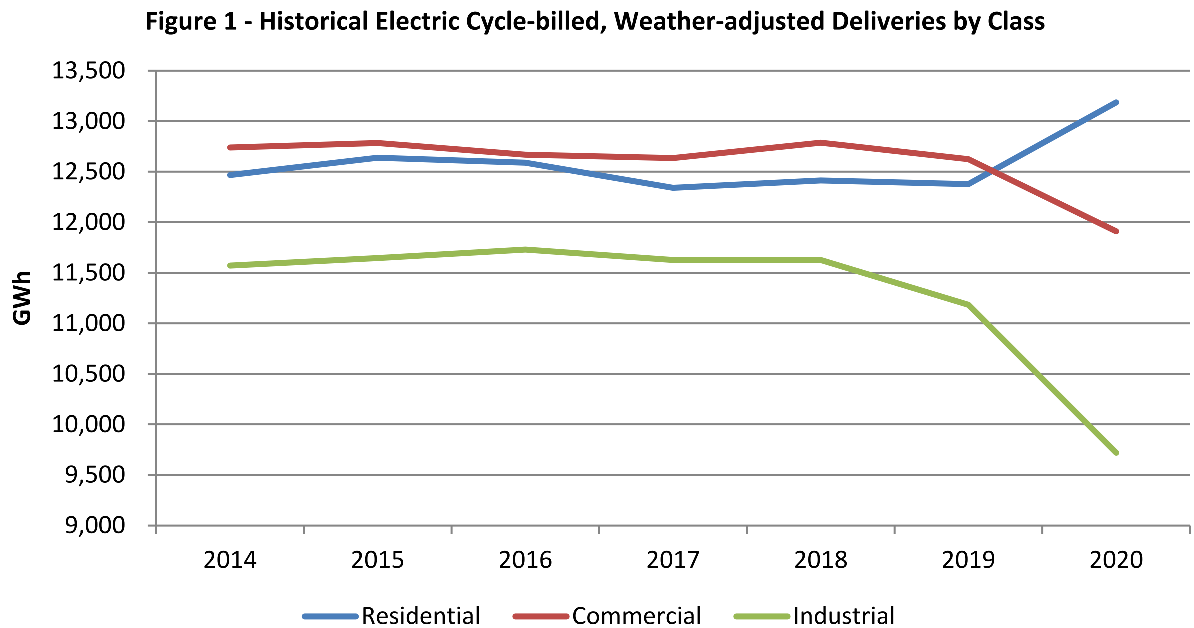
Q. Please explain the criteria used when considering the t-statistics and p-values associated with the model coefficients.

A. Regression analysis is used to develop models that minimize the variance between the actual data and estimates from the models based on the relationship between dependent and independent variables. A numerical coefficient ("β") is estimated for each independent variable in the model and represents the best linear unbiased estimate for that variable's contribution toward explaining the dependent variable. The t-statistics and p-values are used to gauge the relevance of each independent variable in the model. The t-statistic and p-values measure the statistical significance of including a particular independent variable based on a probability distribution. A t-statistic above 2 and p-value below 5% for a particular β suggests the independent variable is statistically significant and is appropriate to include in the regression model. Independent variables with t-statistics below 2 and p-values above 5% suggest the variable should be excluded from the model since it does little to explain the dependent variable. In addition, the direction (positive or negative coefficient sign) and magnitude of each coefficient are also considered when determining to include or exclude variables from the models. The models' independent variable t-statistics and p-values are within these ranges and are, therefore, considered relevant.

SECTION III: HISTORICAL AND FORECASTED ELECTRIC DELIVERIES

Q. Please explain the Company's historical levels of electric deliveries for the five-year period from 2015 to 2020.

A. In the past five years, weather-normalized electric deliveries decreased at a -1.2% Compound Annual Growth Rate ("CAGR") from 2015 to 2020, with most of the observed loss occurring in the industrial class (-3.6%), followed by the commercial class (-1.4%). The residential class showed an increase of 0.9% during this five-year period. These changes are graphically depicted in Figure 1.



Q. What is the cause of the decrease in weather-normalized residential and commercial deliveries from 2014 to 2017 in the Company's service territory?

A. In large part, the retraction in the residential and commercial sectors is caused by a nearly flat population growth in the electric service territory during this period, coupled with increased energy efficiency efforts, starting in 2008.

Q. What is the cause of the sudden residential increase and commercial/industrial ("C&I") decrease of the 2020 weather-normalized deliveries, as shown in Figure 1?

A. Following 2019, the Company's deliveries were impacted by the COVID-19 virus and the resulting pandemic. In 2020, the pandemic caused significant customer behavioral changes, as well as state-mandated restrictions, that caused an increase in "work from home," and the halting or reducing operations of some C&I customers.

Q. What is the expected impact of COVID-19 to deliveries in the long-term?

A. Though the impact was significant to the separate customer classes and overall Company deliveries, projected deliveries are expected to return to pre-pandemic levels starting in 2022.

Q. What are the near- and long-term delivery expectation in the base case forecast?

A. In the short-term, total electric deliveries are expected to increase by 4% in 2021 over 2020, and reflects a "bounce back" due to the COVID-19 pandemic period. Total 2021 deliveries are expected to slightly decrease at a CAGR of -0.4% compared to 2019 (pre-pandemic year) and are expected to increase at a CAGR of 0.5% through the next five years (2020 to 2025). Longer-term, projecting to the end of the IRP forecasting period (2040), total deliveries are expected to grow at a modest 0.4% annually. The annual class-level results of the electric deliveries forecast process are shown in Exhibit A-93 (EMB-1). The implications and effects of this forecast in the IRP are addressed by Company witness Sara T. Walz.

Q. Please describe the process used to determine the Company's total generation requirements.

A. Per the 2018 System Loss Study, the forecasted total electric deliveries are increased by a line loss factor of 7.73% to determine the Company's total bundled generation requirements, shown in Exhibit A-96 (EMB-4).

Q. Is the 2018 System Loss Study the latest available?

A. The 2018 System Loss Study was the latest available study at the time the base case projections were created.

Q. Did the Company evaluate or otherwise forecast electric deliveries related to electric vehicles ("EV")?

A. Yes.

Q. What growth rates of registered EVs has the Company experienced in its service territory?

A. In 2017, there were a total of 4,714 registered EVs in the Company's electric service territory. This number grew to 8,978 registered EVs by the end of 2020, which yields a CAGR of 24%.

Q. What are the projections surrounding EVs in the Company's electric service territory?

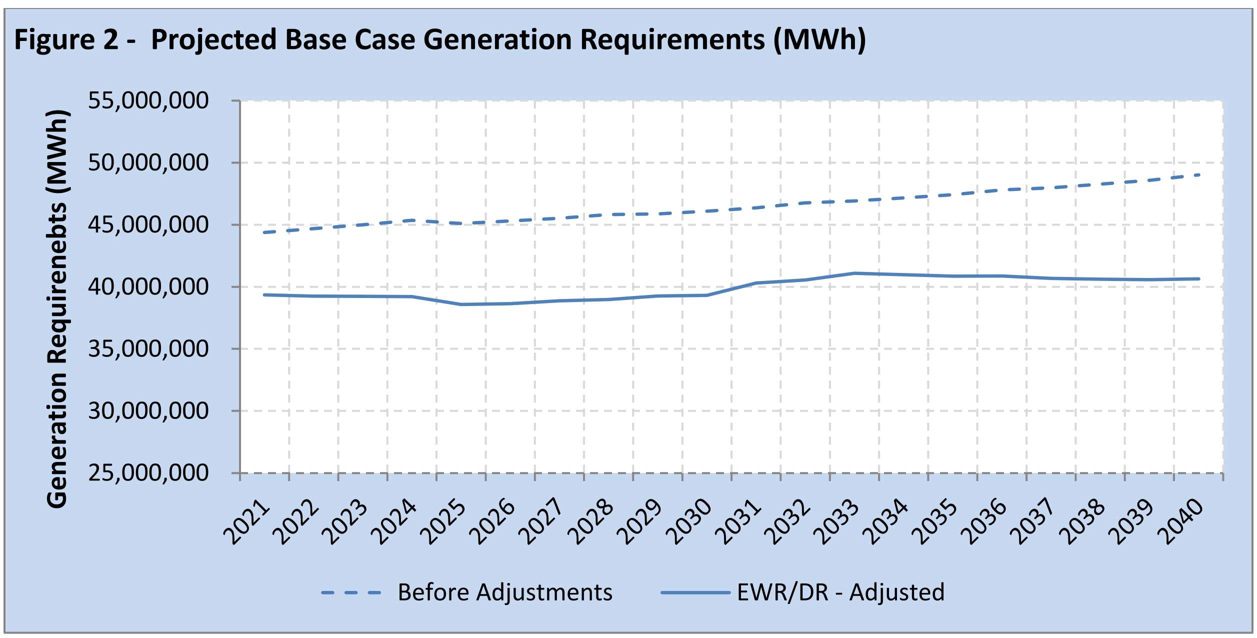
A. The Company is expecting an annual growth rate of EVs on the roads within its service territory of 22.7%, from 2020 to 2040. As of the end of 2020, total registered EVs in Michigan were 23,389, of which 8,978 were within Consumers Energy's service territory. This translates into electric load of 16 GWh in 2020 to 663 GWh in 2040, for a CAGR of 20.3%.

Q. Does the Company include the impact of customer-owned generation, such as net metering and/or self-generation?

A. Any generation produced due to customer-owned net metering and self-generation facilities will reduce the Company's actual deliveries. This reduction of historic load will, in turn, implicitly impact the regression models' coefficients used for projecting electric deliveries and generation requirement. In other words, although the load forecast does not include an explicit adjustment for customer-owned generation, existing sources of customer-owned generation are implicitly included because of the impact to historical load information. Further details related to the implications and effects of net metering/self-generation are addressed by Company witness Keith G. Troyer.

Q. To what extent has the Company reflected future EWR in the electric deliveries forecast you are sponsoring in this case?

A. As discussed in the direct testimony of Company witness Steven Q. McLean, the Company has updated the electric deliveries base case forecast based on the Company's commitment to helping customers reduce energy waste by at least 1.5% per year beginning in 2017. Projected EWR savings are set at 2% through the year 2023, and 1% from 2024 to 2040. Figure 2, below, shows the Company's projected electric load (generation requirements) in MWh with and without adjustments for EWR and Demand Response ("DR").



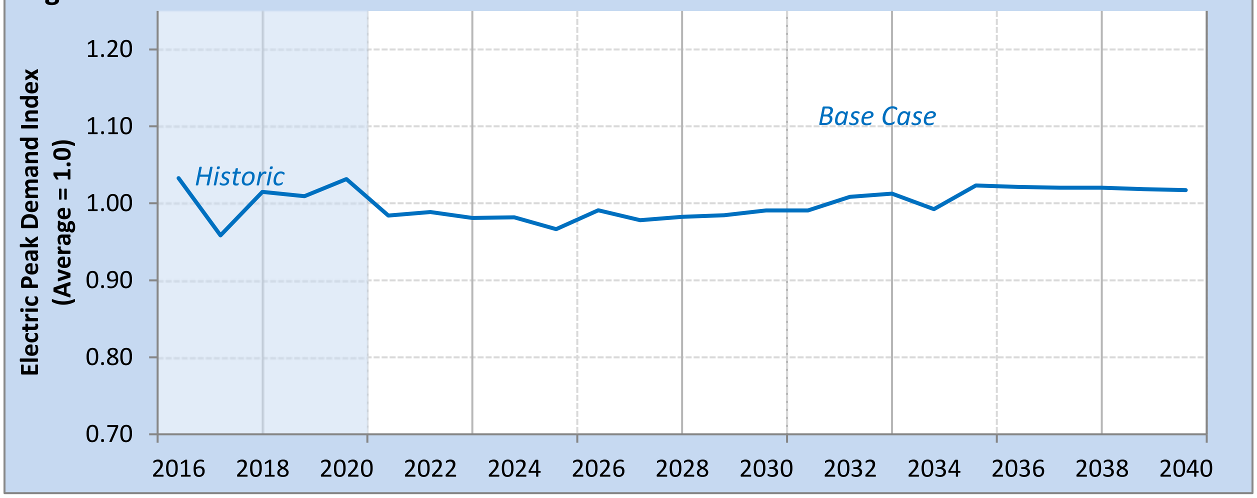
<u>SECTION IV: BASE CASE FORECASTED PEAK DEMAND</u>

Q. What are the expectations for the growth in peak demand for the base case?

A. The Company used regression analysis based on the predicted level of electric deliveries to forecast the peak demand. Weather-normal peak demand grew at a 1.6% CAGR from

2003 to 2007, but reversed much of this trend during the 2007 to 2009 recession when weather-normal peak demand retracted by 4.3%. Looking forward, peak demand is expected to decrease 0.1% per year from 2020 to 2040, the end of the IRP forecast period. The annual system-level results of the peak demand forecast is shown in Figure 3, as well as Exhibit A-94 (EMB-2).

Figure 3 - Historical & Base Case Forecasted Peak Demand Index



Q. What peak demand adjustments are included in the base case?

A. Overall peak demand is adjusted by the following programs/processes: EWR, CVR, DPP, and RSP.

Q. What is the peak demand impact of EWR over the IRP forecast horizon?

A. The EWR Program is projected to reduce peak demand by 699 MW in 2021. The cumulative reductions produced by the EWR Program are expected to increase to 1,158 MW by the end of the IRP projection period (2040). EWR program details are covered by Company witness McLean.

Q. What is the peak demand impact of CVR over the IRP forecast horizon?

A. CVR measures are estimated to reduce peak demand by 21 MW in 2021, increasing to 122 MW by the end of the IRP time horizon (2040). CVR program details are covered by Company witness Henry.

Q. What is the peak demand impact of DPP over the IRP forecast horizon?

A. The Company's DPP Program reduces peak demand by 20 MW from 2021 to 2040. These programs are being implemented as part of the Company's Smart Energy infrastructure investments in which customers are provided technology and information to better manage their impact on the Company's system. DPP programs are covered in more details by Company witness Emily A. McGraw.

Q. Are capacity-side DR resources accounted for in the Company's peak demand forecast?

A. No, capacity-side DR resources, such as Residential AC Peak Cycling and Commercial and Industrial DR, which includes Rate GI and Rate EIP, are registered with Midcontinent Independent System Operator, Inc. ("MISO") and are accounted for outside of this peak demand forecast.

Q. To what extent is the Company's new RSP rate expected to impact peak demand projections?

A. The newly introduced RSP is expected to reduce the Company's peak demand by approximately 122 MW throughout the IRP's forecast horizon.

Q. How did the Company derive at this RSP peak demand reduction?

A. During the summer of 2019, the Company had an RSP pilot program in place with approximately 48,000 residential customers. This pilot group exhibited behavior that shifted an average of 3.5% load from the on-peak hours (2pm to 7pm) to the off-peak hours (7pm to 2pm) in the month of July.

Q. Please explain the process used to identify the peak demand impacts of the Company's EWR and CVR programs.

A. The Company developed hourly load profiles for the Smart Energy and EWR programs. The monthly energy savings associated with each of these programs are integrated with the corresponding load shape to develop hourly demand savings curves.

SECTION V: FORECAST UNCERTAINTY

Q. Is there uncertainty associated with this forecast?

A. The forecasts provided in this case are the Company's best estimate of future electric sales and peak demand. As with any estimate, actual conditions may differ from those assumed in the forecast. The econometric models perform well over the sampling period, accounting for more than 90% of the variations in electric sales and peak demand. The models are expected to perform equally well over the forecast period, but may depart from actuals in instances of structural shifts. This would include significant events absent from the historic period used in the models, such as natural disasters.

Q. Are the exogenous forecasts used in developing the overall sales and peak demand forecasts subject to uncertainty?

A. Yes, all input assumptions are subject to uncertainty. For instance, the Company uses IHS Markit economic forecasts of population, employment, and industrial productivity in developing its sales and peak demand forecasts. As such, the Company's forecasts will change as IHS Markit updates its economic forecasts to capture newer data.

Q. Is there uncertainty associated with customer behavior?

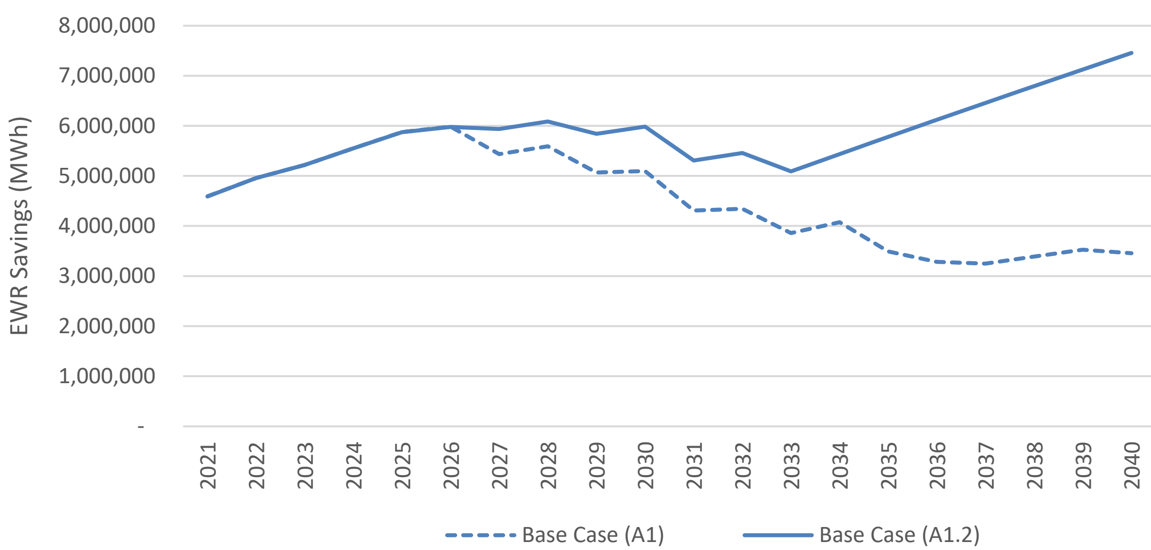
A. Yes, the econometric models use historical customer behavior in developing the forecasted electric sales and peak demand. Anticipated changes in behavior, such as energy efficiency or the downturn in the polycrystalline industry, are then added to the forecasts to capture future expectations. However, if customers behave differently than reflected in the historical data as adjusted for expected actions, then the sales and peak demand forecasts may differ from actual levels.

SECTION VI: ALTERNATIVE FORECASTED GENERATION REQUIREMENTS AND DEMAND SENSITIVITIES

Q. The sensitivities discussed below are compared to the base case forecast. Was this base case forecast a revised version?

A. Yes, the original base case forecast has been revised with modified EWR savings projections from 2023 to 2040. Figure 4, below, shows the EWR difference between versions. Company witness McLean covers the details behind this change in EWR savings projections.

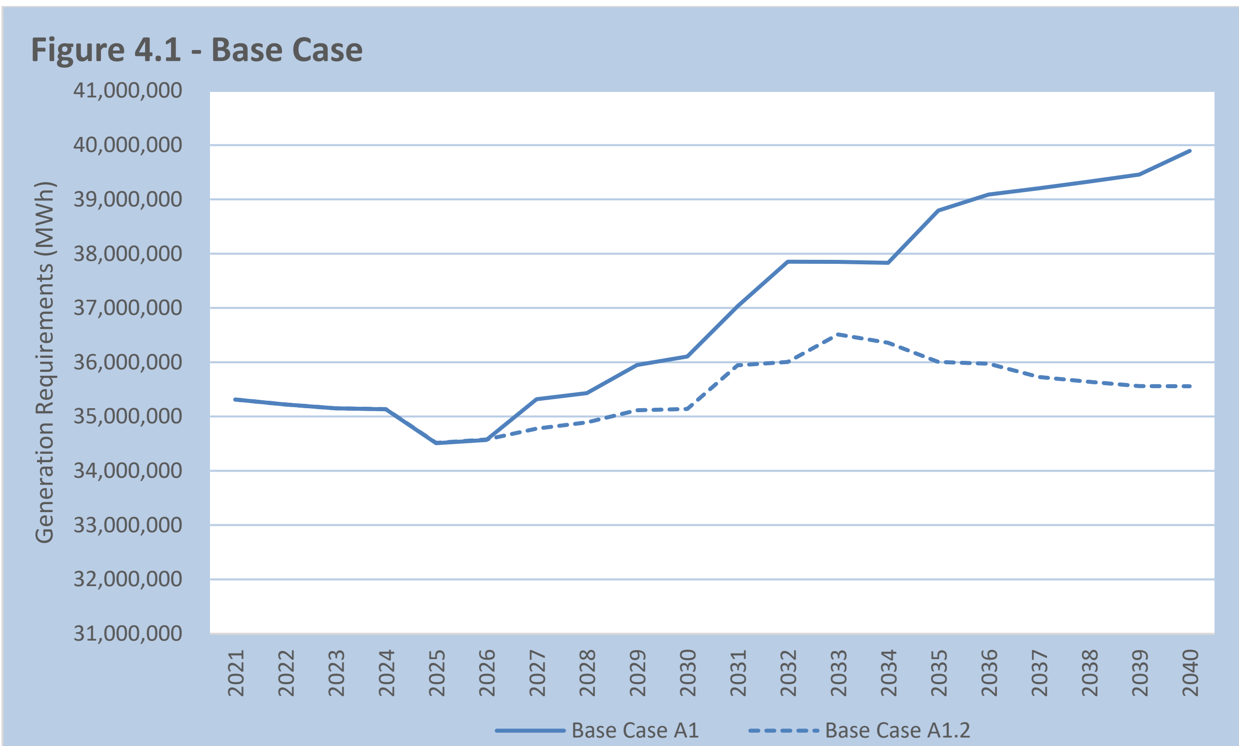
Figure 4 - Energy Waste Reduction - Base Case



Q. With the modified EWR savings projections, what is the impact to the overall generation requirement?

A. Figure 4.1 shows the difference in generation requirements (in MWh) between the base case ("Base Case A1") and the revised base case ("Base Case A1.2").

The modified cumulative impact of EWR savings projections results in decreased levels of generation requirements of 4,336,996 MWh and 612 MW of peak demand. This yields a 2021-2040 CAGR of 0.04% for generation requirements and 0.1% peak demand.



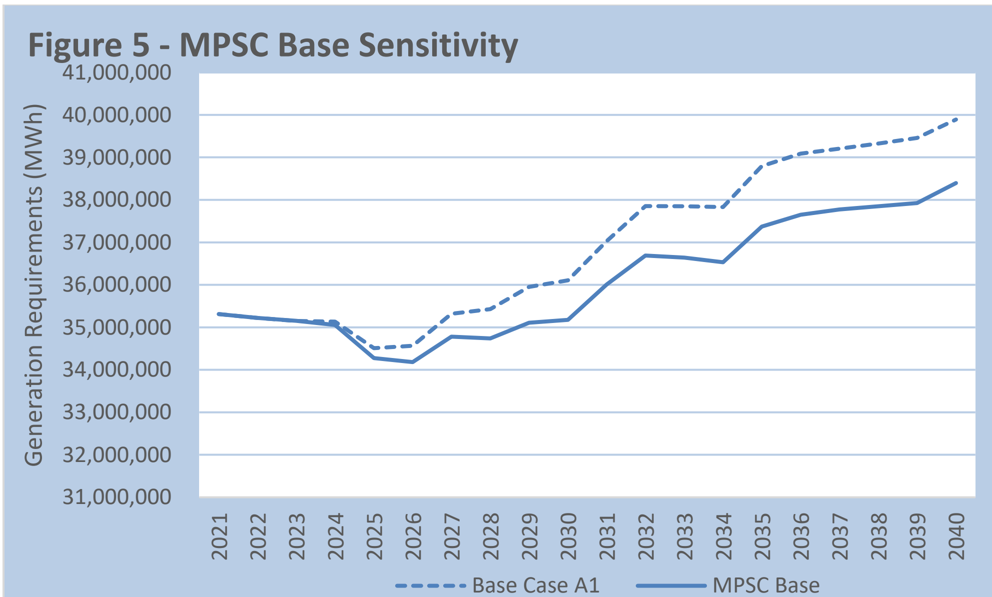
Q. Please briefly explain the different forecast deliveries and peak demand sensitivities that are included in this IRP.

A. In addition to the base case, as described in the testimony above, there are six different sensitivities developed off of this base case. Those are:

1. "MPSC Base" Sensitivity - This sensitivity includes an increased level of energy waste reduction. From 2024 to 2040, the EWR savings level is increased from the base case levels of 1% to 1.5%.

Over the IRP forecast horizon (2021-2040), these increased EWR savings projections result in decreased levels of generation requirements of 1,495,902 MWh and 206 MW of peak demand, compared to the base case A1. This yields a 2021-2040 CAGR of 0.4% for both generation requirements and peak demand.

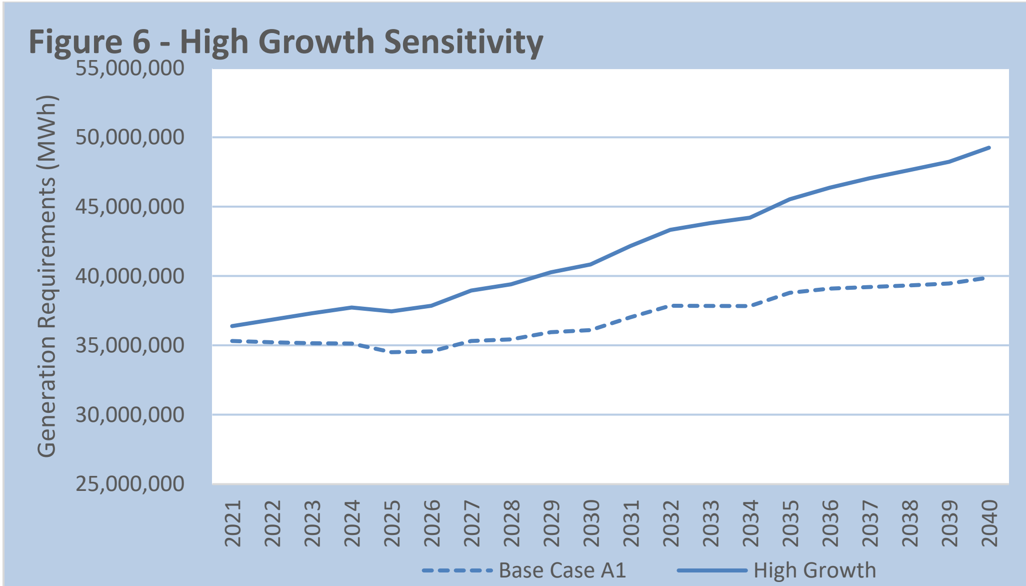
Figure 5, below, shows the difference in generation requirements (in MWh) between base case and MPSC Base sensitivity.



2. High Growth Sensitivity - This sensitivity introduces higher electric deliveries forecast due to accelerated economic growth of 1.5%. This sensitivity has the total Company electric deliveries increased by 1.5% annually from 2021 to 2040, simulating unusual economic growth in the Company's electric service territory. EWR projections are appropriately adjusted (increased savings) to reflect the electric delivery increase.

Over the IRP forecast horizon (2021-2040), this sensitivity results in increased levels of generation requirements of 9,363,548 MWh and 1,392 MW of peak demand, compared to the base case A1. This yields a 2021-2040 CAGR of 1.6% for generation requirement and 1.3% for peak demand.

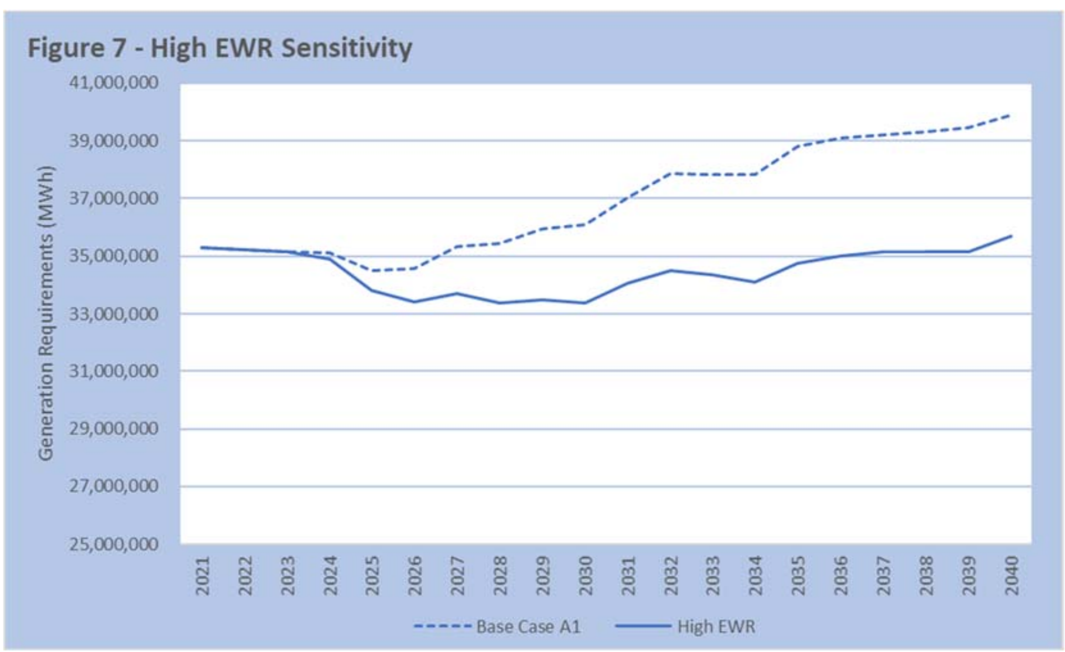
Figure 6, below, shows the generation requirement difference between base case and the High Growth Sensitivity.



3. High EWR Savings Sensitivity – This sensitivity assumes an EWR savings rate of 2.5%. This sensitivity assumes an increase in the annual EWR rate from 1% (base case) to 2.5% starting in the year 2024 until 2040.

Over the IRP forecast horizon (2021-2040), this sensitivity results in decreased levels of generation requirements of 4,195,300 MWh and 578 MW of peak demand, compared to the base case A1. This yields a 2021-2040 CAGR of 0.1% for both generation requirement and peak demand.

Figure 7, below, shows the difference between base case and this sensitivity.

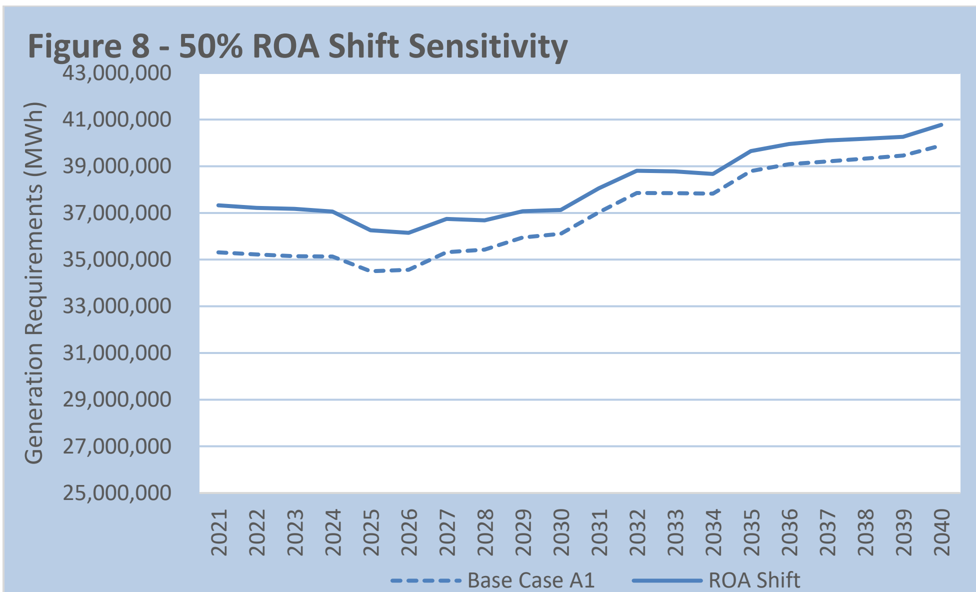


4. Retail Open Access ("ROA") Shift Sensitivity – 50% of current electric ROA load is shifted to the Company's bundled, or full-service, load;

This sensitivity assumes an immediate increase in the Company's full-service customers which, in turn, increases the EWR projections that are incorporated in the forecast. The EWR impact due to this ROA shift does reduce the overall electric load from 2021 to 2040.

Over the IRP forecast horizon (2021-2040), this sensitivity results in increased levels of generation requirements of 888,005 MWh and 63 MW of peak demand, compared to the base case A1. This yields a 2021-2040 CAGR of 0.5% for generation requirement and 0.4% peak demand.

Figure 8, below, shows the difference between base case and this sensitivity.

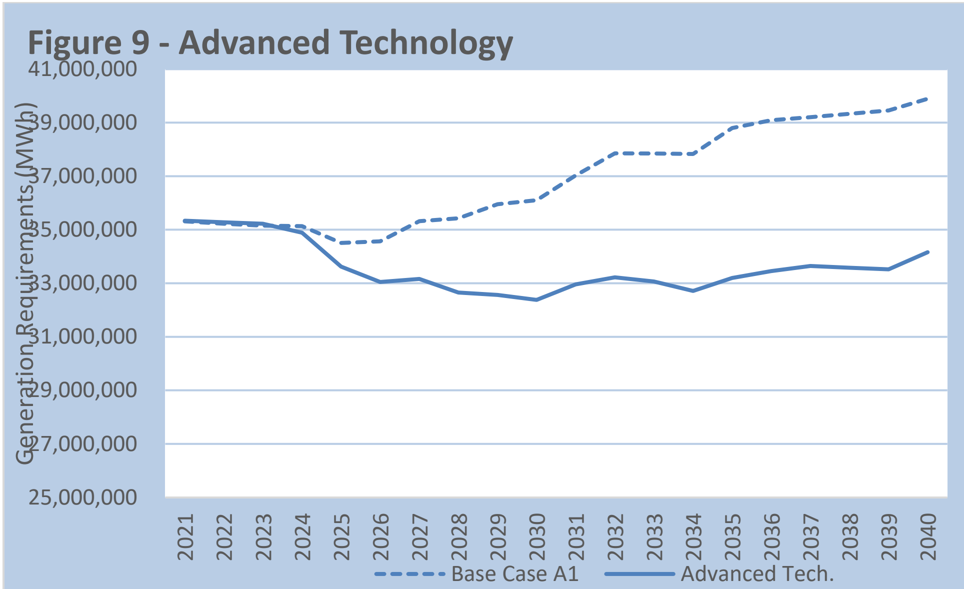


5. Advanced Technology Sensitivity – This sensitivity assumes a 2% EWR savings rate from 2021 to 2040, which is 1% higher than base case from the year 2024 to 2040.

This sensitivity further assumes 31% increased levels of fleet electrification within the Company's electric service territory. This is incremental to the EV load that is projected in the base case forecast. Company witness Myrom covers the details behind the increased fleet electrification.

Over the IRP forecast horizon (2021-2040), this sensitivity results in decreased levels of generation requirements of 5,733,859 MWh and 775 MW of peak demand, compared to the base case A1. This yields a 2021-2040 CAGR of -0.2% for generation requirement and -0.01% peak demand.

Figure 9, below, shows the difference between base case and this sensitivity.

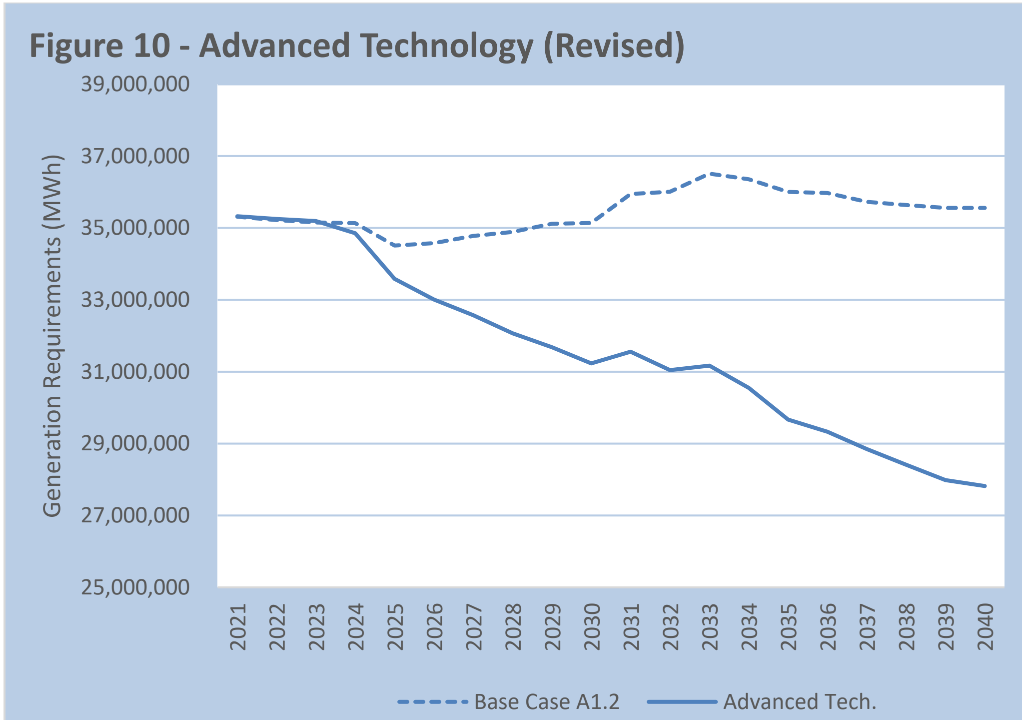


6. Advanced Technology Sensitivity (Revised) – This sensitivity is identical to previous sensitivity ("Advanced Technology") with the exception of the EWR savings projections. This revised Advanced Technology sensitivity includes the modified EWR savings projections as described earlier.

Over the IRP forecast horizon (2021-2040), this sensitivity results in decreased levels of generation requirements of 7,736,767 MWh and 476 MW of peak demand, compared to the base case A1.2. This yields a 2021-2040 CAGR of -1.2% for generation requirement and -0.6% peak demand.

Figure 10, below, shows the difference between base case and the revised Advanced Techology sensitivity.

Company witness McLean covers the details behind this change in EWR savings projections.



Q. Please explain Exhibit A-95 (EMB-3).

A. Exhibit A-95 (EMB-3) is a one-page exhibit that shows the electric peak demands results for the Company's bundled load from 2021 to 2040. The CAGR for 2021 through 2040 shows the long-term impacts of the sensitivities compared to the base case forecast.

Q. Please explain Exhibit A-96 (EMB-4).

A. Exhibit A-96 (EMB-4) is a one-page exhibit that shows each of the different sensitivities outlined above, compared to the base case. This exhibit also shows the 2021-2040 CAGRs for each of the sensitivities.

Q. Does this conclude your direct testimony?

A. Yes.

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 Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))))	Case No. U-21090

DIRECT TESTIMONY

OF

TERESA E. HATCHER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

Q. Please state your name and business address.

A. My name is Teresa E. Hatcher, 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. In what capacity are you employed?

A. I am the Executive Director of Electric Regulatory and Strategy for Electric Grid Integration.

<u>QUALIFICATIONS</u>

Q. Please describe your educational background and business experience.

A. I received a Bachelor of Science degree in Mechanical Engineering, with distinction, from Worcester Polytechnic Institute in 1997 and a Master of Business Administration degree from the University of Michigan Ross School of Business in 2007. From July 1997 to December 1999, I was employed by Consumers Energy as a system engineer, responsible for the Air Ejector, Condensate, and Radioactive Waste Gas Systems' health at Palisades Nuclear Power Plant. From December 1999 to November 2007, I was employed by CMS Enterprises where I held positions as a project engineer responsible for the design and construction of a chemical process facility and was promoted to Senior Plant Engineer for an 800 MW independent gas combined cycle power station. I was then promoted to the position of Asset Manager, responsible for partnership and contract management for biomass, coal/biomass, and hydro independent power stations. Finally, I was promoted to the position of Production Manager for an 800 MW independent power gas combined cycle power station. From November 2007 to December 2008, I was employed as an associate consultant for a management consulting firm in their energy practice area. From January 2009 to January 2011, I was employed as a Technical Development Manager responsible for evaluating potential power plant acquisitions and validating operating and maintenance costs of those acquisitions. Plant fuel types included gas (simple cycle and combined cycle), coal, wind, and biomass. In 2011, I rejoined Consumers Energy as Principal Field Leader responsible for the Gas Transmission and Storage Planning and Scheduling organization, and in October 2012, the position responsibilities were expanded to include planning for Gas Distribution and Service. In 2014, I accepted the position of Corporate Strategic Planner responsible for Distribution, Operations, Engineering, and Transmission organization business strategy. In 2015, I was promoted to Director of Strategic Initiatives as part of the Company's Strategy group. In July 2017, I transitioned to Director of Renewable Energy, responsible for the development of strategies to manage the Company's Renewable Energy Plan ("RE Plan"), Renewable Energy Credits ("RECs"), and renewable energy programs. In April 2020, I was promoted to Executive Director of Electric Regulatory & Strategy Implementation, responsible for the Company's electric regulatory support and compliance activities for Michigan Public Service Commission ("MPSC"), Federal Energy Regulatory Commission, North American Electric Reliability Corporation, and Midcontinent Independent System Operator, Inc.

Q. Have you previously provided testimony before the MPSC?

A. Yes. I provided testimony in:

- Case No. U-18231, the Company's 2017 RE Plan (Direct and Rebuttal Testimony);
- Case No. U-18142, 2017 Power Supply Cost Recovery ("PSCR") Plan (Rebuttal);
- Case No. U-20068, 2017 PSCR Reconciliation (Direct Testimony);

- Case No. U-20171, 2017 Renewable Energy Cost Reconciliation (Direct Testimony);
- Case. No. U-20165, 2018 Integrated Resource Plan ("IRP") (Direct and Rebuttal Testimony);
- Case No. U-20483, 2018 Renewable Energy Cost Reconciliation (Direct Testimony); and
- Case No. U-20483, 2018 PSCR Reconciliation (Direct Testimony).

Q. What is the purpose of your direct testimony?

A. My direct testimony will:

- Describe the Company's existing renewable generating units;
- Provide a comparison of the assumptions between the Company's approved 2017 RE Plan (Case No. U-18231), its 2021 RE Plan Amendment (Case No. U-20984), and this IRP;
- Provide the nonvolumetric surcharge and the regulatory liability balance forecast through the end of the RE Plan period (2029);
- Discuss how the Company will meet the Renewable Energy Credit Portfolio Standards ("RPS") consistent with the Company's RE Plan and the renewable energy resources planned within the IRP Proposed Course of Action ("PCA"); and
- Describe how the combined amounts of Renewable Energy and Energy Waste Reduction ("EWR") compare to the 35% Renewable Energy Goal in Section 6t(5)(e) of 2016 PA 341.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-97 (TEH-1)	IRP Proposed Course of Action - 15% RPS Forecast; and
Exhibit A-98 (TEH-2)	IRP Proposed Course of Action - 35% Goal Outlook.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

SECTION I: EXISTING RENEWABLE UNITS

Q. Please describe the Company's existing renewable generation resources.

A. The Company's existing renewable generation resources consist of 13 hydroelectric facilities, four operational wind farms, and four operational solar facilities.

Q. Please describe the Company's hydroelectric facilities.

A. The Company has 13 hydroelectric facilities from which the Company receives RECs. These are included in the calculation of Exhibit A-97 (TEH-1), column (e). The hydroelectric facilities are discussed further in the direct testimony of Company witness Norman J. Kapala.

Q. Please describe the Company's wind facilities.

A. The Company has completed construction of the Lake Winds Energy Park project and the Cross Winds Energy Park Phases I, II, and III. The Company has recently completed construction of the Gratiot Wind Energy Park, which began commercial operation in December 2020, adding an additional 150 MW to the wind portfolio. The Company also recently acquired the 166 MW Crescent Wind Energy Park, which began commercial operation in February 2021.

Q. Please describe Consumers Energy's existing solar facilities.

A. The Company owns and operates four solar facilities:

- Grand Valley State University ("GVSU") constructed in the spring of 2016 generating up to 3 MW of electricity;
- Western Michigan University ("WMU") constructed in the summer of 2016 generating up to 1 MW of electricity;
- Circuit West Solar, a 500 kW Research and Development roof top urban solar project, which became operational on October 31, 2018; and
- Cadillac Solar, a 500 kW solar project approved in Case No. U-20649 and scheduled for commercial operation in June 2021.

GVSU, WMU, and Cadillac Solar support the Company's Voluntary Green Pricing Program, Solar Gardens. Voluntary Green Pricing Programs are discussed in further detail in Company witness Sarah R. Nielson's testimony.

Q. Please provide the Company's owned existing renewable generating units and associated capacity.

A. The table below summarizes the Company's renewable generation portfolio, including the age, capacity factor, licensing status, and remaining estimated time of operation for each facility in the portfolio:

Resource	In-Service Date	Age (years)	Estimated Retirement Date	Estimated Remaining Time of Operation	Licensing Status	Generating Capacity (MW)	Capacity Factor
Lake Winds	2012	6	2043	25	Active	100.8	30.68%
Cross Winds (Phase 1)	2014	4	2045	27	Active	110.98	37.82%
Cross Winds (Phase II)	2018	3	2049	31	Active	43.7	39.07%
Cross Winds (Phase III)	2019	2	2049	30	Active	76.32	39.4%%
Gratiot Wind Farm	2020	0.5	2051	31	Active	150	29.70%
Crescent Wind Farm	2021	0.4	2052	31	Active	166	27.60%
Heartland Wind Farm	2022 (planned)	0	2053	31	Construction	200	27.2%
Solar Gardens – GVSU	2016	2	2041	23	Active	3	17%
Solar Gardens - WMU	2016	2	2041	23	Active	1	17%
Circuit West Rooftop Solar	2018	2	2043	23	Active	0.500	13%
Cadillac Solar	2021 (planned)	0	2046	25	Construction	0.450	19.6%

Further discussion for Existing Supply Side Resources is discussed within the IRP Report, Exhibit A-2 (RTB-2), sponsored by Company witness Richard T. Blumenstock. The Company's Renewable Energy Power Purchase Agreements are discussed by Company witness Keith G. Troyer and identified in Exhibit A-45 (KGT-1).

SECTION II: RE PLAN AND IRP RELATIONSHIP

Q. Please discuss the approved renewable energy additions as submitted within the Company's RE Plan, Case No. U-18231.

A. The Company amended its previously approved RE Plan in 2017 by including new wind facilities of up to 525 MW and new solar facilities of up to 100 MW, which was approved on February 2, 2019. Consistent with the approval in Case No. U-18231, the Company has entered three separate wind generation contracts totaling approximately 515 MW. The Company received approval of its 198 MW Build Transfer Agreement ("BTA") with Heartland Farms on March 19, 2021. This project has a Commercial Operation Date ("COD") of December 31, 2022. The Company received approval of its 166 MW BTA with Crescent Wind LLC ("Crescent Wind") on December 6, 2019. Crescent Wind began producing renewable energy in February 2021. Finally, on December 19, 2019, the Company received approval of the 150 MW Gratiot Farms Wind Project, which went into commercial operation in January 2021.

Q. Has the Company also implemented up to 100 MW of solar generation as approved in Case No. U-18231?

A. Yes. The MPSC approved the Company's 100 MW Renewable Energy Purchase Agreement ("REPA") with River Fork Solar, LLC ("River Fork Solar"). River Fork Solar had an original COD of May 31, 2021, however, the schedule was delayed by the required network upgrade construction schedule via a REPA amendment approved by the Commission on October 29, 2020. The COD is now projected to occur by November 30, 2022.

Q. What renewable energy resources were modeled in the Company's IRP?

A. The Company's IRP modeling contained assumptions related to the addition of 525 MW of wind generation to reflect the approved amount of wind generation from Case No. U-18231. The wind facilities include Gratiot Wind, Crescent Wind, and Heartland Wind projects.

Q. Are the IRP assumptions consistent with the assumptions within the RE Plan approved in Case No. U-18231?

A. Generally, yes. The IRP has the input assumption of 525 MW of new wind, which is consistent with the RE Plan. The 10 MW variance is a negligible difference between the RE Plan and the IRP. The RE Plan CODs are consistent with those modeled in the IRP. Additionally, the 100 MW of solar addition in 2022, as planned within the IRP, is consistent with the RE Plan in that the RE Plan also planned for a total addition of up to 100 MW of solar.

Q. Please discuss the proposed renewable energy additions as submitted within the Company's current RE Plan Amendment in Case No. U-20984.

A. The Company's Amended RE Plan can be summarized as follows:

- Maintain the Company's RE Plan as approved in Case No. U-18231 as discussed above; and
- Modify the RE Plan to add up to 1,000 MW of new wind and solar facilities, based on customer subscriptions, to support the Company's Large Customer Renewable Energy Program ("LC-REP") growth.

Q. Are the IRP assumptions consistent with the assumptions within the RE Plan Amendment in Case No. U-20984?

A. No. The IRP does not model the currently proposed LC-REP expansion due to the modeling for the IRP being complete prior to the RE Plan Amendment filing and uncertainty in the technology type and amount being procured to meet the LC-REP's needs. The Company will adjust and reconcile the project actuals into the IRP's approved PCA. The purpose of the incremental additions as proposed in the case is to provide additional energy and RECs for specific customer program subscriptions and as such will be assigned to specific subscribing customers in the program. Additional details on the LC-REP are available in the direct testimony of Company witness Nielson.

SECTION III: NON-VOLUMETRIC SURCHARGE AND THE REGULATORY LIABILITY BALANCE

Q. How does this proposed RE Plan Amendment in Case No. U-20984 impact the projected regulatory liability balance?

A. As discussed by Company witness Marc A. Bleckman in Case No. U-20984, the current projected regulatory liability balance at the end of the RE Plan period is approximately \$22 million, which is approximately \$105 million lower than the approximately \$128 million projected in the Company's approved RE Plan (Case No. U-18231). The projected liability balance reflects two specific goals of the Company with regards to the regulatory balance:

(i) maintain a liability position throughout the RE Plan, as required by 2008 PA 295; and

(ii) minimize the projected balance at the end of the RE Plan.

Q. Are there any risks related to the current forecast of non-volumetric surcharge and regulatory liability balance?

A. Yes. Consistent with the RE Plan Amendment in Case No. U-20984, a surcharge is not anticipated at this time; however, the projected regulatory liability balance approaches a regulatory asset position from 2027 through 2028 as shown in Exhibit A-2 (MRB-2) in the Company's RE Plan Amendment in Case No. U-20984. This continues to put the Company's RE Plan at risk of needing to institute a surcharge, despite the projection to hold a liability position by the end of the RE Plan.

SECTION IV: REC PORTFOLIO STANDARD AND RENEWABLE ENERGY GOALS

Q. How does Consumers Energy calculate its REC portfolio obligation?

A. Consumers Energy has elected to calculate its REC portfolio obligation based on the average number of retail sales for the previous three years in accordance with MCL 460.1028(2)(b)(ii).

Q. Has the Company developed a sales forecast through 2029 for compliance with the renewable energy standard?

A. Yes. Consistent with the Company's RE Plan methodology, the REC portfolio obligation is based upon the average number of retail sales in MWh for the previous three years, as mentioned above and shown in Exhibit A-98 (TEH-2), column (b).

Q. Is the 35% Goal, specified in Section 1 of 2008 PA 295, calculated in the same manner as the REC portfolio?

A. No. The 35% Goal calculation is a combination of the forecasted number of RECs received in a given year plus the energy efficiency savings achieved in the same year through the Company's EWR Program. Energy efficiency savings and projections are discussed by Company witness Steven Q. McLean.

Q. What is the impact to the availability of RECs due to the IRP's PCA?

A. The Company plans to meet the 15% RPS in 2021 through the projects outlined in the Company's RE Plan, Case No. U-18231. This is represented within the PCA and described in the previous sections of my direct testimony. The IRP PCA results in progressively increased percentages of renewable energy through the end of the plan period. In 2021, the Company projects to need 4,912,147 RECs to meet the 15% RPS, and projects to meet this need as shown in Exhibit A-97 (TEH-1), column (d).

Q. What is the PCA's impact to the 35% Goal?

A. The 35% Goal is a combination of RECs, from renewable energy, and cumulative energy efficiency savings, from the EWR program. The PCA achieves the 35% Goal in 2023, two years ahead of the current target year of 2025. The RECs and cumulative energy efficiency savings are forecasted to reach 50% by 2025. The Company projects cumulative energy efficiency savings to be 8,555,165 MWh and 7,644,527 RECs to be in the year 2025 to achieve a 50% Goal, as described in Exhibit A-98 (TEH-2), column (p).

Q. Does the IRP assume that the RECs associated with the Public Utility Regulatory Policies Act of 1978 ("PURPA") based contracts in the IRP are included with future contracts?

A. No, the Company has not projected any RECs from future PURPA-based contracts based upon the MPSC's May 31, 2017 Order in Case No. U-18090, conveying 100% ownership of RECs to the Qualified Facilities. Without negotiated contracts, it would be imprudent to assume RECs are available from future Qualified Facilities.

<u>SECTION V: SUMMARY</u>

Q. Will you please summarize your direct testimony?

A. The IRP is consistent with the approved RE Plan and provides for a glide path for renewables that allows the Company flexibility to meet customer demand, as well as achieve RPS and Clean Energy Goals.

Q. Does this complete your direct testimony?

A. Yes.

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 Approval of an Integrated Resource Plan	)	Case No. U-21090
under MCL 460.6t, certain accounting	)	
approvals, and for other relief.	)	
______________________________________	)	

DIRECT TESTIMONY

OF

NATHAN J. WASHBURN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

Q. Please state your name and business address.

A. My name is Nathan J. Washburn, 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 the Director of Distributed Energy Resources/Instrumentation and Controls ("DER/I&C") Design. I began my employment at the Company in January of 2009 in High Voltage Distribution Lines Design and Standards where I developed standards for the Company's high voltage distribution lines. In April of 2012, I was assigned to the Substation Design and Standards division where I oversaw civil engineering for the Company's substations. In April of 2017, I was tasked with developing the Company's Unmanned Aircraft Systems Program as well as the front-of-the-meter Battery Storage Program. In February of 2021, I assumed my current position.

Q. What are your responsibilities as Director of DER/I&C Design?

A. My responsibilities as Director of DER/I&C Design include management of the Company's:

- instrumentation and controls design for substations, lines, and other assets;
- design of self-performed front-of-the-meter solar and battery sites; and
- technical specifications for front-of-the-meter solar and battery site solicitations.

Q. What is your formal education experience?

A. I received a Bachelor of Science degree in Civil Engineering from Michigan State University in 2008.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. No.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to describe the value of the Battery Energy Storage System ("BESS") prototypes in the Company's Integrated Resource Plan ("IRP") filing. Throughout my testimony, I may refer to a BESS as "energy storage" or a "battery" interchangeably, they are intended to mean the same thing except where context indicates otherwise. Specifically, my direct testimony includes:

1) Section 1: Introduction/Changes from the 2018 IRP;
2) Section 2: Energy and Capacity Prototype Overview;
3) Section 3: Solar Plus Storage Prototype Overview;
4) Section 4: Distribution Asset Upgrade Deferral Prototype Overview;
5) Section 5: Ancillary Services Market Prototype Overview; and
6) Section 6: Summary of Direct Testimony.

SECTION 1: INTRODUCTION/CHANGES FROM THE 2018 IRP

Q. Did the Company expand the use of energy storage prototypes in the Company's 2021 IRP?

A. Yes. The 2018 IRP included the "Energy and Capacity" energy storage prototype. At the time, the value that lithium-ion batteries could provide for the distribution grid, and in the Midcontinent Independent System Operator Inc. ("MISO") ancillary service market, was not well known. With the experience that the Company has gained with its energy storage projects, additional research, and learnings that have been gathered in the industry, the Company determined that new prototypes could capture additional value in the 2021 IRP.

Q. How did the Company choose what prototypes should be included in the 2021 IRP?

A. To determine which prototypes should be included in the 2021 IRP, the Company considered the possible use cases that a lithium-ion battery could serve. Of the possible use cases, there were four that had a value that could be specifically calculated. These use cases became the Company's four energy storage prototypes which are:

1) Energy and Capacity;
2) Solar Plus Storage;
3) Distribution Asset Upgrade Deferral; and
4) Ancillary Services Market.

Q. Why did the Company include these prototypes in this IRP?

A. In general, batteries are very flexible and can be used for more than one use case. However, the Company's modeling software, Aurora, is currently only utilized to capture storage behavior of charging and discharging in response to energy price signals. More complex use cases of storage, such as peak shaving or ancillary service market participation, are not included in the Company's Aurora simulations. The values of these use cases were calculated outside of Aurora and provided for each prototype as a credit in the form of cost reductions in Aurora. The three new prototypes were developed to specifically capitalize on the additional value that can be created by "stacking" use cases. The Solar Plus Storage, Distribution Asset Upgrade Deferral, and Ancillary Services Market prototypes can all provide energy and capacity value during the hours that they are not performing their primary service, in addition to the revenue generated by their primary service. By incorporating these prototypes into the Company's 2021 IRP, the real value of energy storage systems are more accurately captured.

Q. Were storage technologies other than lithium-ion based batteries considered?

A. Although other storage technologies exist, lithium-ion was the only technology considered for these prototypes due to the Company's experience with lithium-ion, the maturity of available cost estimates for lithium-ion, and the fact that most other storage technologies have not yet been demonstrated to be widely commercially viable.

Q. What characteristics do the prototypes have in common?

A. Each of the four battery prototypes have several characteristics in common:

1. The storage has a four hour-duration, which means it can discharge at maximum power output over a four-hour period;
2. All prototypes except Distribution Asset Upgrade Deferral[1] have an assumed effective load carrying capacity ("ELCC") of 95%. (e.g. a 100 MW battery will yield 95 Zonal Resource Credits (ZRCs));
3. The BESS have an assumed round trip efficiency of 85%;
4. Daily energy throughput is limited to one energy-equivalent cycle per day which aligns with typical industry limits that are captured in performance warranties;
5. All prototypes except Solar Plus Storage are designated as "allow partial build" in Aurora, which enables the modeling software to select the optimal build size between a given minimum and maximum;
6. All but the Solar Plus Storage prototype have an assumed 15-year operating life. The Solar Plus Storage prototype operating lifetime is modeled as 30 years. The costs for the Solar Plus Storage system are modified to account for the necessary augmentation that would be required for the battery to achieve the longer lifetime;
7. The first year that each prototype can be built is 2025; and
8. All prototypes except Solar Plus Storage assume a year 2020 fixed Operating and Maintenance expense of $33/kW-year and a capital cost of $1,304/kW-AC. These numbers are modified year after year based upon price forecasts as explained by Company witness Jeffrey E. Battaglia.

[1] See Section IV for a discussion on the ELCC of the Distrbution Asset Upgrade Deferral battery prototype.

Q. Was a prototype considered for the "islanding" (outage mitigation) use case?

A. The Company considered modeling an islanding battery, which is a battery that provides power to customers during an outage. However, there was no good publicly available data adequate for estimating the total value of the outage minutes that an islanding battery would mitigate. Therefore, accurately calculating the value of the islanding prototype was not practical.

SECTION 2: ENERGY AND CAPACITY PROTOTYPE OVERVIEW

Q. What is the Energy and Capacity prototype?

A. The Energy and Capacity battery prototype is functionally the same as the Company's Energy and Capacity storage offering from the 2018 IRP. This four-hour duration battery charges energy from the grid when energy prices are low, and discharges when prices are high. Aurora selects the optimal amount of storage to build up to a maximum of 500 MW each year.

Q. How is the value of Energy and Capacity prototype determined?

A. Unlike the other prototypes, the Energy and Capacity prototype has no external cost offsets applied to account for additional revenue. Aurora models the energy time shifting and calculates the associated revenue.

SECTION 3: SOLAR PLUS STORAGE PROTOTYPE OVERVIEW

Q. What is the Solar Plus Storage prototype?

A. The Solar Plus Storage prototype is a hybrid system consisting of a 100 Megawatts-Alternating Current ("MW-AC")/200 Megawatts-Direct Current ("MW-DC") solar array that is DC-coupled with a 30 MW/120 MW-hour (four-hour duration) battery. This means that the site has enough solar panels to generate a maximum of 200 MW-DC of power, and that the system's inverters, which invert the DC current generated by the panels to AC current suitable for the power grid, have a combined power capacity limit of 100 MW-AC. A DC-coupled site connects the solar and storage assets on the DC side of the power conversion system ("PCS") or inverter.

Q. What are the benefits related to DC coupling?

A. DC coupling offers at least three benefits:

1) The solar and storage share interconnection equipment, which reduces costs;

2) Energy that would otherwise be lost to an AC-coupled system's inverter capacity limit can be captured and stored in the battery to be released later in time. This results in an increased capacity factor of the solar unit; and

3) The storage resource is Investment Tax Credit ("ITC") eligible, assuming the storage unit charges at least 75% of its energy from the solar asset. As the percent charged from solar increases past 75%, so too does the ITC. For example, if the energy storage charges 80% of the time from the solar, it is eligible for 80% of the credit. If it charges 100% of the time, it is eligible for 100% of the credit. This prototype was modeled to meet the minimum requirement of 75% to obtain the credit.

Q. How was the solar size determined for the Solar Plus Storage prototype?

A. The 100 MW-AC power rating was selected due to the availability of cost estimates around this size. The 200 MW-DC size was selected because a higher inverter loading ratio ("ILR") of 2.0, when paired with storage, provides the opportunity for a higher capacity factor when compared to a traditional solar ILR which might be 1.3.

Q. How does a site's ILR affect its capacity factor?

A. A solar site's ILR (also known as the DC-to-AC ratio) is the ratio between the solar panels' total DC generation capacity and the inverter's AC capacity. For example, a solar asset with 130 MW-DC of solar panels and a 100 MW-AC inverter would have an ILR of 1.3. Increasing a solar asset's ILR will, in general, increase its capacity factor. However, during hours of peak generation, the solar panels may generate power in excess of the inverter's power rating, and that power will be lost. Typically, a solar site's ILR is selected as a careful balance between wasted energy (that is clipped by the inverter), energy production, revenue requirements, and costs.

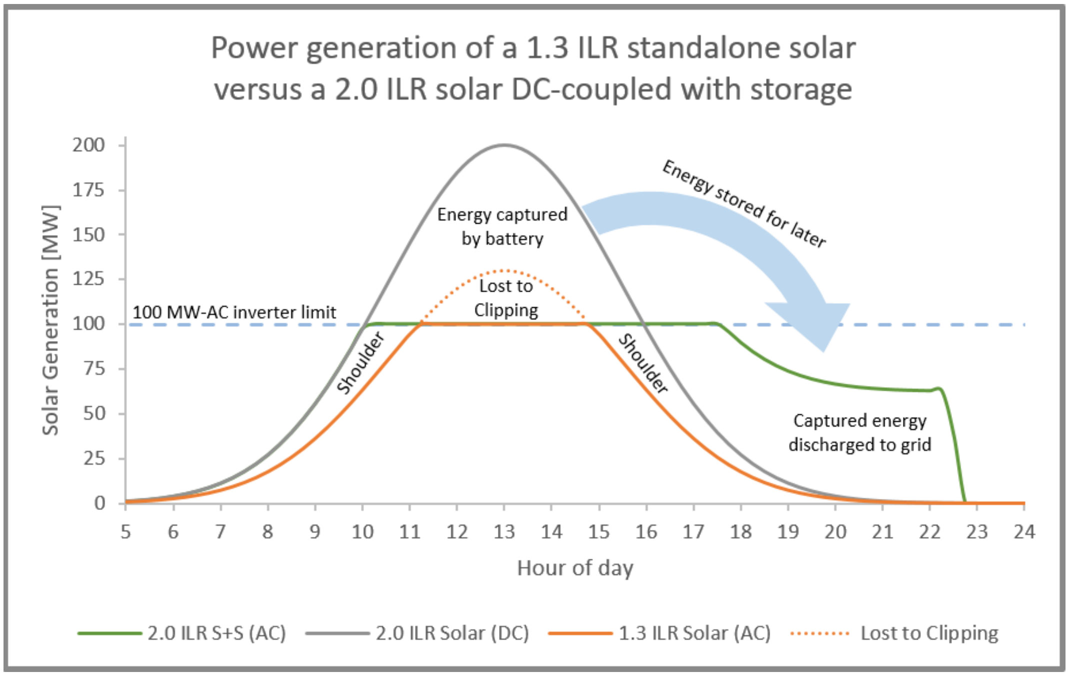


Figure 1: Showing the power generation of a 1.3 ILR standalone solar versus a *2.0 ILR solar site DC-coupled with storage*

Q. How does DC coupling solar and storage increase a site's ILR?

A. Observe Figure 1 above, showing the AC power generation of a 1.3 ILR standalone solar site (1.3 ILR Solar (AC)), the DC power generation of a 2.0 ILR standalone solar site (2.0 ILR Solar (DC)), and the AC power generation of a 2.0 ILR solar plus storage site (2.0 ILR S+S (AC)). As described above and observed in the figure, the 1.3 ILR solar site's power generation is limited during peak generation hours by the 100 MW-AC inverter capacity limit. The standard term for this limitation is "clipping". Similarly, the DC generation of the 2.0 ILR standalone solar site is observed to rise above the inverter limit which would also be lost to clipping. When DC-coupled with storage, solar generation in excess of the inverter's capacity can be captured and stored in the battery for release during non-maximum generation times. This is identified in the figure as "Energy captured by battery" and the release of the energy as "Captured energy discharged to grid." This action results in a net higher capacity factor of the solar unit because the total amount of energy discharged to the grid is increased when compared to a similar site without DC-coupled storage.

Note also that a higher ILR further increases the site's net capacity factor as more energy is generated and released to the grid during the mornings, evenings, and during days without clear skies as illustrated as the "shoulders" in Figure 1. As shown in Figure 1, DC-coupling storage with solar reduces the site's clipped energy and increases the site's capacity factor.

Q. What is a generating asset's capacity factor?

A. A generating asset's capacity factor is the ratio between the asset's theoretical maximum generation capability versus the asset's actual generation output over a period of time, typically a year. An ideal solar site that had the sun shining directly overhead 24 hours a day, 7 days a week would have a capacity factor of 100%. However, solar sites have periods of reduced generation (e.g. nighttime or cloudy weather) and therefore have a capacity factor of less than 100%. For a typical solar-only site with an ILR of 1.3, National Renewable Energy Laboratory ("NREL") data used for modeling solar in the IRP assumes a capacity factor of 23.4%.

Q. Please explain why an ILR of 2.0 was selected?

A. An ILR of 2.0 was selected for this prototype because it increases the capacity factor of the solar plus storage site. The 2.0 ILR was selected by using NREL's System Advisor Model ("SAM") to simulate a 30 MW-DC/120 MWh battery co-located with solar with the following configurations:

1) 1.3 ILR (100 MW-AC, 130 MW-DC);
2) 1.5 ILR (100 MW-AC, 150 MW-DC); and
3) 2.0 ILR (100 MW-AC, 200 MW-DC).

In each simulation, solar and meteorological data for Blissfield, Michigan was used, due to it being roughly central to the expected geographic area of future solar deployments and because of the availability of high quality solar irradiance data for that area. To capture ITC benefits, the storage was simulated as having received at least 75% of its energy from the solar in the model.

The cost of a solar site is approximately proportional to its DC capacity, as the bulk of the costs are for the modules themselves. Therefore, relative to a base 1.3 ILR standalone solar system, a 1.5 ILR site with a battery costs approximately 15% more and provides a 10.76% capacity factor ("CF") increase (0.72% CF increase per 1% cost increase), and a 2.0 ILR site with a battery costs approximately 54% more and provides a 28.68% CF increase (0.53% CF increase per 1% cost increase). It is acknowledged that in this simple comparison, there is a differential in the capacity factor increase per dollar when comparing the 2.0 and 1.5 ILR sites. In practice, solar panel costs will be reduced with orders of scale, reducing this differential. It is also much more likely that ITC credits could be obtained for charging from solar with a higher ILR, and that consideration is not reflected in this comparison. An ILR of 1.5 is not entirely uncommon for standalone solar. For example, when comparing a 1.5 ILR to a 2.0 ILR version of a specific stand-alone solar site, the 1.5 ILR site may clip 9% of energy while the 2.0 ILR site may clip up to 22%. In the final analysis, an ILR of 2.0 is more characteristic of the anticipated future of Solar Plus Storage sites than lower values, which is why it was chosen.

Q. How was the storage size determined for the Solar Plus Storage prototype?

A. A balance between the costs and benefits was considered when selecting the storage size. Figure 2 illustrates the general concept of how costs and benefits vary in relation to energy capacity.

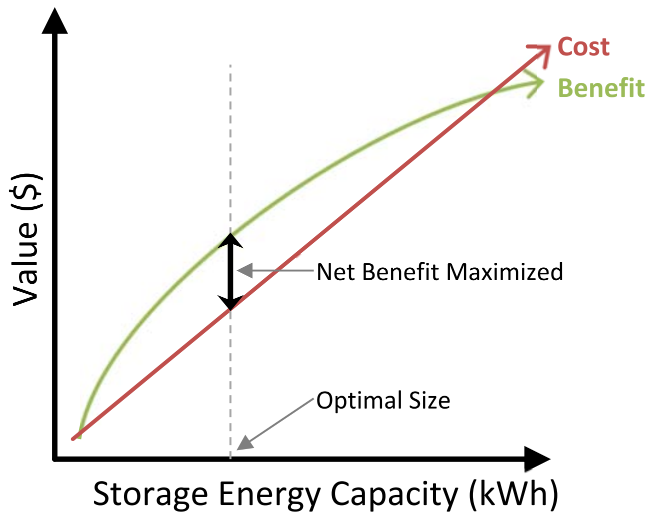


Figure 2: Showing the optimal sizing strategy for storage when considering costs and benefits

The cost of battery storage tends to scale somewhat linearly with the battery's energy capacity. At some point, the benefits of increasing the energy capacity have diminishing returns. The highest value is realized when the net benefit is maximized. The cost curve and the benefit curve will change given a specific project's site requirements, vendor availability, and material costs at the time of the project. Given the variability and uncertainty of both the costs and benefits, a "one size fits all" approach to sizing solar plus storage will not be accurate for any specific project. Therefore, parameters such as the storage duration and the solar to storage ratio are guided by industry trends, data availability, and related observations rather than by specific data or analysis. A four-hour duration was selected because it is common in the industry which provides a higher confidence level in related modeling efforts. Likewise, a ratio of 10 MW of solar per 3MW of storage (10:3) was selected as it is within the range of commonly observed ratios in the industry, typically 4:1, 3:1, or 2:1. These selections resulted in a storage size of 30 MW/120 MWh.

Q. How were the Solar and Storage assets modeled in Aurora?

A. Aurora does not have the capability to explicitly model a DC-coupled solar plus storage site. Therefore, to model the Solar Plus Storage prototype in Aurora, a solar site and a storage asset are modeled together, and the solar site's Forced Outage Rate ("FOR") profile is modified to produce the expected capacity factor resulting from DC-coupling the storage. Aurora models a solar site's generation using a FOR profile, which is a profile of the percentage in each hour of the site's maximum theoretical AC generation that is not being utilized for each hour of the year, for a total of 8760 values. As an example, at a particular hour, a site projected to be generating at 60% of its maximum AC capacity will have an FOR of 40%. The Company used Michigan-based FOR profiles for a standalone single-axis tracker solar site with a 1.3 ILR. In order to use this solar-only FOR profile for the solar aspect of the solar plus storage prototype, the FOR profile needed to be modified to account for the capacity factor increase realized by both the ILR increase from 1.3 to 2.0 and the benefits of DC-coupling with storage.

Q. Explain how the FOR has to be modified to accurately model the DC-coupled Solar Plus Storage prototype.

A. A solar site's capacity factor may be readily calculated from the year-long FOR profile. When modeled in NREL's SAM, the 2.0 ILR solar plus DC-coupled storage site shows an increase of 28.68% in capacity factor when compared with a 1.3 ILR standalone solar site, such that the resulting capacity factor used for the solar component of the Solar Plus Storage prototype is 31.7%. Therefore, the solar-only FOR profile's numbers were uniformly increased (or "boosted") to result in a 28.68% capacity factor increase. For example, an FOR of 40% (generating at 60% capacity) would be boosted to generating at 77.2% capacity, or an FOR of approximately 22.8%. However, consider the instance of the asset generating at 90% of capacity (an FOR of 10%). After boosting, the asset is now generating at 115.8%, with an FOR of -15.8%. This new "boosted FOR profile" was intended to be used in Aurora for modeling the 2.0 ILR solar plus storage's solar site, however it now contained instances of the FOR being negative (i.e. the generation being greater than 100%) which caused errors in Aurora. Although mathematically the new "boosted FOR profile" was producing the desired energy output, Aurora could not model it. The Company's modeling team decided therefore to "double the AC capacity and halve the AC generation" of the solar aspect of the solar plus storage prototype. The FOR profile was modified to produce half the energy generation, and the model was adjusted to use 200 MW-AC instead of a 100 MW-AC as the capacity for the solar site. Costs and build limits were modified subsequently as well so that Aurora saw no changes other than being able to now model the Solar Plus Storage asset. By doubling the capacity and halving the generation, each hour's total energy output remained the same. As an example, if there was an hour in which the "boosted FOR profile" said that the 100 MW-AC site was generating at 120% of capacity (i.e. generating 120 MW-AC of power), Aurora could not model this. Accordingly, the generation is halved and the capacity is doubled so that Aurora was now modeling a 200 MW-AC site generating at 60% capacity (i.e. generating 120 MW-AC of power). Any instances where the "boosted FOR profile" brought generation above 100% were now below 100% and could therefore be modeled in Aurora effectively.

Q. How does Aurora model the value of the "clipped" energy that would be captured by the battery in the Solar Plus Storage prototype?

A. There are modeled hours where the AC energy generation of the solar is in excess of the actual site's capacity. This is intentional. It is intended to be reflective of the DC-generated energy that would, in the real world, be stored in the DC-coupled battery and discharged later in the day. As Aurora cannot model DC generation or this several-hour-later discharge, and because this DC energy generation is of a non-trivial amount, the energy is allowed to be discharged immediately out on to the grid. While this is not strictly accurate, it is more accurate than discarding the energy entirely, and is the best approximation of the behavior of the solar plus storage prototype that can be modeled with the Company's tools. Additionally, due to seeking to abide by the ITC credits requirements, the storage was modeled to charge at least 75% of its energy directly from the solar asset. Therefore, most of this excess energy produced during the day ends up cycling through the battery in an approximation of expected real world behavior anyway.

Q. Please summarize your testimony on the Solar plus Storage Prototype.

A. The result of the analysis for the solar plus storage prototype was a 100 MW-AC/200 MW-DC solar site paired with a 30 MW/120 MWh storage site. The solar site had a capacity factor of 31.7%, in line with NREL's SAM modeling of this type of asset. Aurora was not limited to how many MW of these prototypes it could construct in any given year. The energy generation profile that is used to model the Company's typical solar sites was modified (increased) for the solar component of the Solar Plus Storage prototype to account for the benefits of the DC coupling and the high DC-to-AC ratio.

SECTION 4: DISTRIBUTION ASSET UPGRADE DEFERRAL PROTOTYPE OVERVIEW

Q. What is a Distribution Asset Upgrade Deferral prototype?

A. A Distribution Asset Upgrade Deferral battery is a storage system that defers the upgrade of a distribution substation.

Q. How were substations selected for deferral?

A. Substations were deemed eligible for deferral if their existing load was over 80%, and their projected overload year was between 2020 and 2040. A substation's existing load was defined as the highest peak demand from 2015 to 2019. The annual load growth rate was calculated based on the annual peaks during that same period. The projected overload year was determined by applying the annual load growth rate to the existing substation loading.

The substation configurations were used to further filter the substation selection. Group regulated substations, which commonly have reduced footprints, require comprehensive rebuilds and may involve relocation as part of the capacity increase. Converting a group regulated substation to circuit regulation, which would include transformer bank replacement, is as costly as building a new substation. In 2020 dollars, this cost was estimated between $1,100,000 and $1,500,000. The approximate cost to upgrade each substation's capacity was estimated based upon previous projects with similar capacities and upgrade needs. The distribution asset upgrade deferral use case offers the most financial benefit for substations that need more costly upgrades.

The result of applying the filters described above yielded 23 substations eligible for the distribution asset upgrade deferral use case for the study period between 2020 and 2040. The deferral period from the calculated overload year was assumed to be 15 years.

Q. How was the value of the Distribution Asset Upgrade Deferral prototype determined?

A. The value of the Distribution Asset Upgrade Deferral battery is the avoided cost of a substation upgrade prevented by the battery's implementation. The avoided cost for the substation upgrade deferral, in 2020 dollars per battery kW, is calculated as follows. The approximate load on the circuit, after the 15-year deferral period, was calculated based on the annual load growth. The existing load was subtracted from the load at year 15 to determine the Mega Volt-Amperes ("MVA") that the battery would have to produce to satisfy the increased load at the end of the deferral period. A power factor of 1 is assumed, such that 1 MVA of increased load is satisfied by 1 MW of battery power. A 3% annual inflation rate was applied to the estimated cost of upgrade in 2020 dollars to determine the cost in the upgrade year. The present value of this upgrade was calculated in 2020 dollars assuming a discount rate of 7%. The avoided cost of the upgrade was calculated as the difference between the estimated cost of the upgrade if performed today and the present value of the deferred upgrade, all in 2020 dollars. The avoided cost per battery kW was then calculated for each of these substations. Ignoring one outlier whose estimated cost was approximately 10 times that of the median value due to its unique configuration, the population of 22 had a median cost avoided per battery kW of $194.21, and a standard deviation of $226.85. The average avoided cost was $329.57/kW. The average battery size was 2.32 MW, with a median size of 2.12 MW, and a standard deviation of 1.31 MW. As a result, the maximum size of the Distribution Asset Upgrade Deferral battery was set at 2 MW with a four-hour duration with a value of $194/kW-year, which is used in Aurora as a cost offset. Due to there being about 20 opportunities in about the 20-year time span of the study, Aurora was limited to modeling one such battery per year, up to 2 MW.

Q. What ELCC does the Distribution Asset Upgrade Deferral prototype receive?

A. Based upon an examination of daily loadings throughout the year, it was determined that the Distribution Asset Upgrade Deferral battery would be needed for peak shaving purposes between June 1 and September 30, Monday through Friday, from 3pm-8pm. This is approximately 5% of the year in which the battery is unavailable for energy and capacity services. Given that loss of availability, it is assumed that the ELCC for this prototype would be slightly lower than for the other battery storage prototypes. To determine this difference in ELCC, these peak shaving periods can be looked at as "outages" and included in the Equivalent demand Forced Outage Rate ("EFORd") calculation. Many of the inputs needed for the EFORd calculation were not readily available for batteries so Ludington Pumped Storage Unit 2 and Ludington Pumped Storage Unit 4 were used as proxies to determine what the adjustment should be. The result of adding the extra "outage time" was that the EFORd for each unit added approximately 8% to their base EFORd. Therefore, it was determined that the 8% EFORd would be added to the base 5% EFORd for batteries which resulted in a 13% EFORd or an 87% ELCC.

SECTION 5: ANCILLARY SERVICES MARKET PROTOTYPE OVERVIEW

Q. How was the value of the Ancillary Services Market Prototype developed?

A. An energy storage system may derive value from participating in MISO's ancillary services market. Due to limitations in data availability, modeling capabilities, and reliable cost estimates, the Company felt that the only ancillary market service that could be modeled with confidence was MISO's "Fast First" frequency regulation market. Although this market did not yet have participants at the time of this IRP's modeling, lessons learned from similar markets in CAISO, PJM, and other independent system operators were used to approximate MISO's Fast First frequency regulation market's anticipated dynamics and limitations.

Sound Grid Partners, LLC ("SGP") was commissioned by the Company to analyze and forecast the revenue potential for an energy storage system that is providing regulating reserve services as part of the MISO ancillary services market. SGP assessed historical and current MISO regulating reserve market dynamics, including changes to the regulating reserves market structure that were implemented on February 26th, 2020 for the purpose of enhancing the efficiency of the market by taking advantage of fast responding resources such as energy storage. SGP's analysis involved making projections about the regulating reserves market size, asset composition, and pricing for years 2021 – 2040. Full details on the analysis may be found in SGP's paper, "Energy Storage System Participation in MISO's Regulating Reserves Market: Revenue estimate analysis: 2021 – 2040."

SGPs analysis showed that a battery participating in the Fast First frequency regulation market had the ability to generate $194/kW-year in 2020. The following assumptions were made to modify the value provided by SGP to account for participation in the energy and capacity market and the unknown nature of MISO's selections in this new Fast First frequency regulation market:

1) At the time of this study, no batteries had entered this market, and so there was no basis for an assumption of how often the battery would be chosen by MISO for participation in the energy market versus the ancillary services market. Therefore, 50% was selected for participation in the energy market;

2) 50% of a year is 182.5 days, and in the energy market, each day the battery would be used for 8 hours (4 hours charging and 4 hours discharging), leaving 7300 hours available in the year for frequency regulation;

3) At the time of this study, no batteries had entered the Fast First frequency regulation market, and so there was no basis for an assumption of how often the battery would be chosen by MISO for performing frequency regulation. The median value of 50% was selected. 50% of the remaining available 7300 hours is 3650 hours of performing frequency regulation; and

4) SGP's analysis of available MISO sample Fast First frequency regulation signals, and a projection of the Average Regulation Day Ahead ("DA") Market Clearing Price ("MCP"), Average Regulation Real-Time ("RT") Mileage MCP, and Average Energy Storage System ("ESS") mileage (all components of calculating frequency regulation revenue), yielded a projected average hourly value of $0.0231/kW-hour for performing frequency regulation. If performed for 3650 hours with an assumed 95% uptime, this yields an approximate value of $80/kW-year for the Ancillary Service Market prototype for 2021. SGP's study's findings underwent similar calculations to determine appropriate Aurora inputs for all modeled years.

SECTION 6: SUMMARY OF DIRECT TESTIMONY

Q. Please summarize your direct testimony.

A. BESSs can be very complicated to model accurately, however they do have the ability to perform multiple services to gain additional value. To capture additional value, this IRP includes four energy storage prototypes. These prototypes are (1) Energy and Capacity, (2) Distribution Asset Upgrade Deferral, (3) Ancillary Services Market (specifically the performance of frequency regulation), and (4) Solar Plus Storage. These prototypes capture not only the value that would be generated from the MISO energy and capacity markets, but also the additional value that can be generated with other value streams.

Q. Does this complete your direct testimony?

A. Yes, it does.

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 Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))))	Case No. U-21090

DIRECT TESTIMONY

OF

SARAH R. NIELSEN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

Q. Please state your name and business address.

A. My name is Sarah R. Nielsen, and my business address is One Energy Plaza, Jackson Michigan, 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Executive Director of Demand Side Management.

Q. What are your responsibilities as Executive Director of Demand Side Management?

A. As Executive Director of Demand Side Management, I lead the Company's programs for Demand Response, Consumers Energy's Voluntary Green Pricing ("VGP") products, Green Generation, PowerMIDrive, and PowerMIFleet.

Q. Please describe your educational and professional experience.

A. I received a bachelor's degree in biology from the University of Dayton, a Master of Business Administration degree from the Yale School of Management, and a Master of Environmental Science degree from the Yale School of the Environment.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to discuss Consumers Energy's current and projected need for VGP products to serve customer demand. Additionally, my testimony presents Consumers Energy's forecast for electric vehicle ("EV") adoption in the Company's electric service territory.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, in Case No. U-20697 related to the Company's EV fleet proposal, PowerMIFleet.

Q. Are you sponsoring any exhibits in this case?

A. No.

<u>Section I: VGP Customer Programs and Demand</u>

Q. Please describe the VGP offerings.

A. Consumers Energy offers a suite of VGPs, including the Large Customer Renewable Energy Program("LC-REP"), Solar Gardens Pilot Program ("Solar Gardens") along with its income-qualified subset MI Sunrise Solar Pilot, and the Renewable Energy ("RE") Credit ("REC") Program, which is comprised of several products including Michigan RECs, Michigan REC New, National RECs, and National REC New. The Company's last biannual VGP filing occurred in Case No. U-20649, which included a forecast of market potential for each VGP. Additionally, the Company filed its latest biannual VGP report in Case No. U-18351. These dockets provide additional information regarding VGP customer research and market potential. Additionally, the Company's RE Plan Amendment Case No. U-20984 provides additional information related to growth potential of the Company's LC-REP.

Q. Please describe the LC-REP.

A. The LC-REP provides full service customers with the opportunity to advance the development of renewable energy by offering customers the ability to match up to 100% of their total annual energy use with renewable energy generated from wind or solar resources. Customers have the opportunity to choose from Option A or Option B of the program. Under Option A, Consumers Energy supplies the renewable energy resource from designated renewable facilities and offers renewable subscriptions to non-residential customers of 150 kW and larger at a levelized cost of electricity. In turn, those subscribers receive Midcontinent Independent System Operator, Inc. ("MISO") market credits on their bill and the RECS are retired or transferred on their behalf. Option A appeals to customers who are interested in a bundled product administered by Consumers Energy to help accelerate renewable development in Michigan utilizing RE Plan resources separate from the Integrated Resource Plan ("IRP"). Given the varying MISO credits and REC prices over time, interested customers usually have a more complex understanding of energy markets and long-term perspective.

Option B of the program allows the Company to administer a Power Purchase Agreement ("PPA") on behalf of the customer at a low administrative fee. This option is available to full service customers adding new primary voltage load not previously served by the Company prior to their enrollment in the LC-REP. At this time, the Company has not had any applicants for Option B over the life of the program.

Q. Please describe the Solar Gardens.

A. Solar Gardens is a voluntary program intended to further the deployment of solar energy in Michigan and meet customer demand. This program is open to all full service electric customers, and has multiple payment options to subscribe to 500 Watt blocks of solar; including up-front, 3-year, 7-year, and month-to-month payments over the life of the resource. As discussed by Company witness Teresa E. Hatcher, the solar facilities that make up the program's pooled resources are located at Western Michigan University (1 MW), Grand Valley State University (3 MW), and in the City of Cadillac (approximately .5 MW). Subscribers also receive MISO market bill credits from the solar fields and RECs are retired on their behalf.

Recently, the Company launched a subset to Solar Gardens called MI Sunrise Solar Pilot that allows non-profits to subscribe on behalf of income-qualified customers and target the bill credits toward those being served. The subscription blocks utilized for the MI Sunrise Solar Pilot are from the same pool of 500 Watt blocks of solar comprising Solar Gardens.

Q. Please discuss the REC Program.

A. The REC Program provides eligible full service customers with the opportunity to subscribe to the environmental attributes of renewable energy by offering customers the ability to utilize RECs to match up to 100% of their total annual energy. There are four different program offerings or products: (1) MI REC, where customers subscribe to RECs generated in Michigan; (2) MI REC New, where customers subscribe to RECs from new RE resources in Michigan; (3) National REC, where customers subscribe to RECs from existing out-of-state resources; and (4) National REC New, where customers subscribe to RECs generated from new out-of-state RE resources. The MI REC product is available to all full service customers. MI REC New, National REC, and National REC New are available to full service non-residential customers. The Company's REC Program offerings are unbundled VGPs, and therefore no market credits are received by subscribers. Similar to the other VGP options however, the RECs are retired on the customer's behalf.

Q. Please describe the source of supply for these VGPs.

A. The RE Plan is the funding model that underpins the vast majority of VGP customer subscription MWh supply. The RE Plan has provided a funding mechanism for the LC-REP and Solar Gardens resources. Only the REC Program products pilots, since they are not bundled subscriptions, presently operate outside of the RE Plan. As LC-REP and

Solar Gardens renewable generation sources are not IRP resources, the IRP is not impacted. The unbundled REC pilots also do not impact the IRP since only the environmental attributes (i.e the RECs) are subscribed. Moreover, since VGPs are not subsidized by non-subscribers, the expansion of the RE Plan for VGPs does not impact IRP costs for subscribers or non-subscribers.

The use of the RE Plan as the funding mechanism has worked well for satisfying VGP customer MWh demand. Of the VGP products, LC-REP has proven to be the largest and fastest growing in terms of MWh subscriptions, and the requested expansion of the LC-REP in Case No. U-20984 will address future MWh needs.

Q. Please describe the forecasts regarding VGP demand considered in the IRP.

A. The VGP MWh planning scenarios in the IRP are the same as what were utilized in the Company's VGP Program filing in Case No. U-20649. These forecasts were developed in consultation with market research, primarily performed by Cadmus, as detailed in that case.

Q. Does the Company anticipate expansion in the LC-REP?

A. Yes. Since Case No. U-20649 and the start of the IRP modeling process, additional market research regarding LC-REP was performed via Accenture. The accelerated forecasts for LC-REP are provided in the Company's recent RE Plan Amendment, Case No. U-20984. This RE Plan Amendment addresses the future growth of the LC-REP. These MWh will be supplied via the RE Plan, and they are separate from the IRP. Furthermore, as the research undertaken was completed in 2021, and any future expansion of LC-REP would occur under the RE Plan, these forecasts were not included in the IRP modeling.

Q. Does the Company anticipate expansion in the Solar Gardens?

A. The Solar Gardens and MI Sunrise Solar pilots recently added the Cadillac solar expansion of 450kWAC, as approved in Case No. U-15805 on September 24, 2020. The planned October 2021 VGP biennial filing will address the proposed path forward regarding additional Solar Gardens expansion; however, with only 4.5 MW currently in the Solar Gardens supply, any needed expansion is not anticipated to have a significant impact on planning given the relative size of Solar Gardens facilities to potential LC-REP expansions.

<u>Section II: Summary of EV Market and Customer Programs</u>

Q. Please provide an overview of the EV market affecting Consumers Energy.

A. There are over 19,000[1] EVs in Michigan, of which approximately 7,200[2] are in the Company's electric service territory as of 2019. The Company maintains a close watch on EV adoption given that the geographic scope of its electric service territory covers the majority of Michigan's lower peninsula. Thus, it is likely that most EV drivers in Michigan will seek charging opportunities from infrastructure powered by Consumers Energy during their travels.

Although EV adoption forecasts and annual growth rates have varied from year to year, all forecasts continue to predict a future trend toward rapid growth of EV adoption. As illustrated in Figure 1 below, the Company has forecasted EV adoption in its electric service territory leading to over 84,000 EVs by 2030. Consumers Energy's projection is

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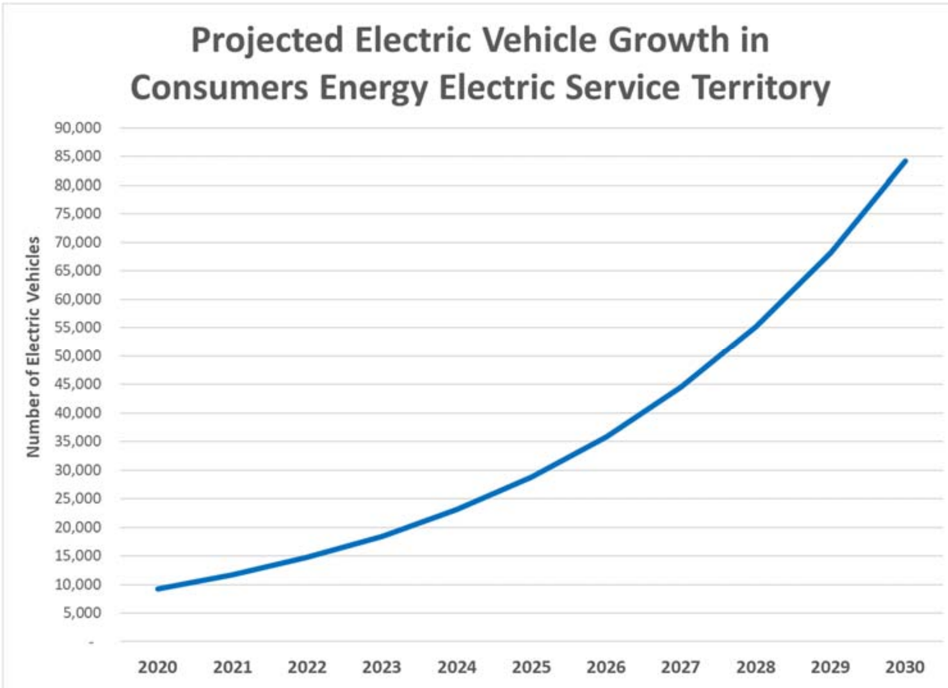
[1] "Advanced Technology Vehicle Sales Dashboard," Alliance of Automobile Manufacturers, 2019. Data compiled by the Alliance of Automobile Manufacturers using information provided by IHS Markit. https://autoalliance.org/energy-environment/advanced-technology-vehicle-sales-dashboard/.
[2] IHS vehicle registrations.

greater than 20% year-over-year EV sales growth, as estimated from Michigan Secretary of State annual EV registration data[3] and national EV sales trends.[4]

Figure 1



The projected growth above is also anecdotally supported by the fact that all major vehicle manufacturers located in Michigan have made public commitments to electrification (e.g. GM, Ford), several entrants to the EV market continue to grow in this sector (e.g. Rivian, Bollinger), and Tesla sales continue to grow. Furthermore, with the recent announcements from auto manufacturers regarding future electrification plans, EV adoption could be even higher than presently projected. Thus, the timing is prudent to identify effective methodologies via the PowerMIDrive and PowerMIFleet pilots to shepherd as much EV load growth as possible to optimum times for the grid and prepare for the electric services needed by an EV-centric transportation sector.

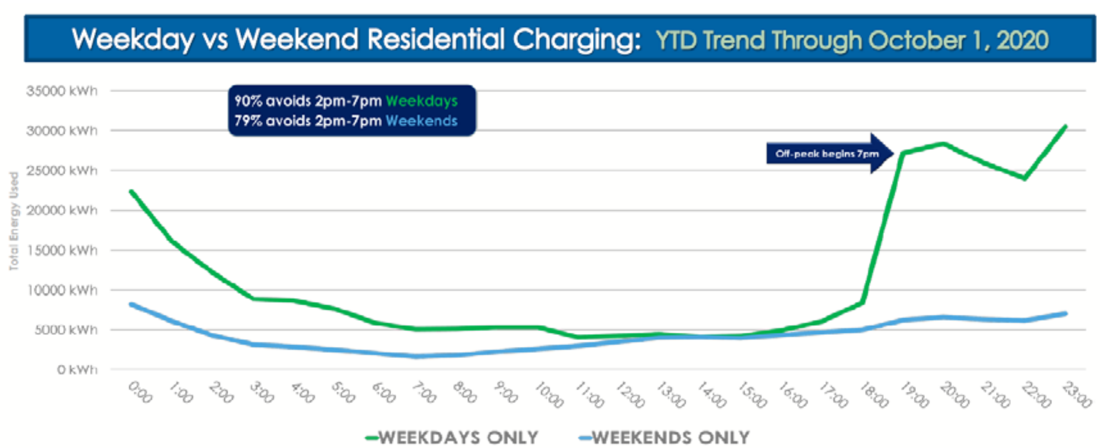
[3] IHS vehicle registrations.
[4] https://www.eei.org/issuesandpolicy/electrictransportation/Documents/FINAL_EV_Sales_Update_April2019.pdf

Q. Will the PowerMIDrive and PowerMIFleet pilots be successful at managing EV charging to minimize IRP impacts?

A. Yes. The initial results of the current PowerMIDrive pilot are encouraging, and strongly suggest that the Company will be successful in developing permanent EV customer programs to maximize off-peak charging. While the PowerMIFleet pilot just started in May 2021, and results are not presently available, it will build upon the lessons learned from PowerMIDrive as much as possible.

For example, on page 50 of Consumers Energy's "PowerMIDrive Annual Report 2020", filed into the record on June 30, 2020 in Case No. U-20134, the Company showed that the combination of a rebate, plus customer education and outreach efforts regarding how to maximize cost savings from a Time of Use ("TOU") rate, resulted in 90% of charging occurring off-peak. This trend has continued even after that report, as seen below in Figure 2.

Figure 2



Additionally, since its launch in June 2019, the PowerMIDrive program has been quite successful at achieving off-peak charging with EV owners via educational efforts and TOU rates with 90% of residential weekly charging happening off-peak. Through the

PowerMIFleet Pilot Program, the Company will be evaluating the impacts of fleet electrification over the next three years to determine what additional planning enhancements may be needed. With approximately 1% of vehicles being EV, at this time, transportation electrification is not significantly impacting IRP planning, but given greater than 20% year-over-year increased adoption of EVs, the Company remains vigilant in monitoring growth and charging trends to ensure that EVs remain a grid benefit and that Consumer Energy can reliably serve all customers' future transportation electrification needs.

In sum, (1) residential EV adoption is still early but experiencing strong growth, (2) the Company has seen success with the current TOU rate and education based programs, but (3) fleet electrification is an emerging area that will better inform planning standards in the near future via PowerMIFleet learnings.

Q. Are there sensitivities in EV adoption scenarios that could affect future IRPs?

A. Possibly, and the Company will be keeping a close eye on several factors. Most importantly, the speed of EV adoption could increase due to sustainability commitments and continued battery price reductions, especially in the fleet sector. For example, fleet owners are likely to make their next vehicle purchase decision based on total cost of ownership more than aesthetics. Thus, if battery cost projections continue to fall, fleet EV adoption could occur at a faster rate than the Company has seen in the residential sector thus far (which is still greater than 20% year over year). Accelerated fleet EV adoption in turn could be a driver for accelerated residential EV adoption given that potential buyers may first experience the benefits of an EV at work before they decide to purchase or lease an EV for themselves.

The Company also believes that fleets may adopt a hub-and-spoke approach with medium duty and heavy duty EVs. For example, having a driver that may be paid hourly idling, in addition to the vehicle charging time, is less efficient than overnight charging while the driver is not on duty and cost savings from TOU rates are possible. Thus, fleet charging could be concentrated at key locations, similar to the residential sector in which a majority of charging occurs at home (or home base of operations regarding fleets). If the hub-and-spoke charging phenomena materializes, it could change planning standards for specific commercial and industrial customer sectors.

Furthermore, newer light duty EVs have traditionally had Level 2 ("L2") charging capabilities of around 7 kW or less, but newer light duty EVs are seeing increased battery sizes and L2 charging capabilities of 11 kW to even as high as 19 kW. These changes could result in differences to residential load profiles, where most of the light duty vehicle charging presently occurs. However, this trend could also be offset if a significant portion of the workforce continues to work remote rather than commute.

Consumers Energy will continue to monitor these and other emerging trends in transportation electrification via the PowerMIDrive and PowerMIFleet pilots, as well as other market sources. At this time, the Company remains confident that managed charging EV programs will be successful and minimize impacts to IRP planning.

Q. Does that conclude your direct testimony?

A. Yes.

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 Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))))	Case No. U-21090

PROOF OF SERVICE

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

Melissa K. Harris, being first duly sworn, deposes and says that she is employed in the Legal Department of Consumers Energy Company; that on June 30, 2021, she served an electronic copy of the **Consumers Energy Company's Application and Testimony and Exhibits of Consumers Energy Company witnesses Richard T. Blumenstock, Sara T. Walz, Anna K. Munie, Thomas P. Clark, Heather A. Breining, Kevin J. Watkins, Srikanth Maddipati, Jason R. Coker, Jeffrey E. Battaglia, Keith G. Troyer, Norman J. Kapala, Brian D. Gallaway, Carolee Kvoriak, Benjamin T. Scott, Teri L. VanSumeren, Steven Q. McLean, Lakin Garth, Emily A. McGraw, Matthew S. Henry, Eugene M. Breuring, Teresa E. Hatcher, Nathan J. Washburn, and Sarah R. Nielsen** upon the persons listed in Attachment 1 hereto, pursuant to a Confidentiality Agreement, at the e-mail addresses listed therein.

Melissa K. Harris

Melissa K. Harris

Subscribed and sworn to before me this 30th day of June, 2021.

Crystal L. Chacon

Crystal L. Chacon, Notary Public
State of Michigan, County of Ingham
My Commission Expires: 05/25/24
Acting in the County of Jackson

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Consumers Energy
Count on Us®

Attachment B – Permanent Cessation Timeline

ACTIVITY – INTERIM MILESTONE	PROJECTED DATE OF COMPLETION	NOTES
NOPP Submittal	10/13/2021	Annual updates to follow
Expected IRP Approval by the MPSC	6/27/2022	
Expected MISO Study Results	2/30/2023	
Anticipated Cold & Dark[1] Outage Specifications Finalized	4/22/2024	
Anticipated Cold & Dark Contract Award	1/26/2025	
Anticipated MPSC[2] and MISO[3] approved Unit 1, 2, & 3 Retirement; Cold & Dark Outage Start	5/31/2025	JH Campbell Units 1, 2, and 3 will no longer generate electricity
Anticipated Cold & Dark Outage Complete	9/6/2025	JH Campbell Units 1, 2, and 3 will be deenergized and ready for AD&D

Notes:

(1) Cold & Dark refers to a period of time where preparations are put in place for Abatement, Decommissioning & Demolition (AD&D).
(2) MPSC is the Michigan Public Service Commission
(3) MISO is the Midcontinent Independent System Operator