

Attachment E

Case 21090 Blumenstock Direct

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

REVISED DIRECT TESTIMONY

OF

RICHARD T. BLUMENSTOCK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

~~June~~ October 2021

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1 **Q. Please state your name and business address.**

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

4 **Q. By whom are you employed?**

5 A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”).

6 **Q. What is your position with Consumers Energy?**

7 A. I am currently the Executive Director of Electric Planning. I began employment at the
8 Company in May 1994 in the electric transmission planning area where I performed
9 planning studies on the Company’s distribution and transmission systems. In April 2002,
10 I was assigned to the electric operations area where I oversaw engineering operations for
11 the distribution and transmission systems. In August 2009, I was assigned to the fuel
12 supply area where I oversaw the Company’s purchasing and transport functions for fuel
13 for electric generation. In June 2011, I assumed additional responsibilities including
14 oversight of the Company’s interaction in the Midcontinent Independent System Operator,
15 Inc. (“MISO”) markets; wholesale settlements and transactions functions; Power Supply
16 Cost Recovery (“PSCR”) activities; and planning for electric supply necessary to satisfy
17 customers’ energy and capacity needs. In September 2019, I assumed my current position
18 as Executive Director of Electric Planning.

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

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

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1 **Q. What is your formal education experience?**

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

4 **Q. Have you previously testified before the Michigan Public Service Commission**
 5 **(“MPSC” or the “Commission”)?**

6 A. Yes, I provided testimony in the following MPSC cases:

- 7 • Case No. U-16045-R: Reconciliation of PSCR Costs and Revenues for the
 8 Calendar Year 2010;
- 9 • Case No. U-16432-R: Reconciliation of PSCR Costs and Revenues for the
 10 Calendar Year 2011;
- 11 • Case No. U-16890: Approval of a PSCR Plan and for Authorization of Monthly
 12 PSCR Factors for the Year 2012;
- 13 • Case No. U-16890-R: Reconciliation of PSCR Costs and Revenues for the
 14 Calendar Year 2012;
- 15 • Case No. U-17429: Approval of a Certificate of Necessity (“CON”) for the
 16 Thetford Generating Plant pursuant to MCL 460.6s and for related accounting
 17 and ratemaking authorizations;
- 18 • Case No. U-17317: Approval of a PSCR Plan and for Authorization of Monthly
 19 PSCR Factors for the Year 2014;
- 20 • Case No. U-17317-R: Reconciliation of PSCR Costs and Revenues for the
 21 Calendar Year 2014;
- 22 • Case No. U-17752: Authority to amend its renewable energy plan (“REP”)
 23 approved in Case Nos. U-15805, U-16543, U-16581, and U-17301;
- 24 • Case No. U-17678: Approval of a PSCR Plan and for Authorization of Monthly
 25 PSCR Factors for the Year 2015;
- 26 • Case No. U-17678-R: Reconciliation of PSCR Costs and Revenues for the
 27 Calendar Year 2015;
- 28 • Case No. U-18250: Application of Consumers Energy for a financing order
 29 approving the securitization of qualified costs and related approvals associated
 30 with the early termination of the Palisades Nuclear Energy Plant (“Palisades”)
 31 Power Purchase Agreement (“PPA”);

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- 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

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1 Energy Plan. After extensive modeling and analysis, the Company has refreshed its 2018
2 IRP and has developed a better plan for Michigan. The Company is seeking approval of
3 an IRP in this case which will help Michigan lead a faster clean energy transformation by
4 accelerating the Company's exit from coal-fired generation while increasing electric
5 reliability and reducing energy market purchase volatility when compared to the
6 Company's currently approved IRP. Through the acquisition of existing gas plants, and
7 the continued commitment to key elements of the Company's Clean Energy Plan, the
8 Company has developed an IRP which does not sacrifice reliability, affordability, or the
9 financial stability of Consumers Energy.

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

- 22 1) The accelerated retirement of the Company's D.E. Karn ("Karn") Units 3 and
23 4 from May 31, 2031 to May 31, 2023, J.H. Campbell ("Campbell") Units 1
24 and 2 from May 31, 2031 to May 31, 2025, and Campbell Unit 3 from
25 December 31, 2039 to May 31, 2025, and the replacement of those resources

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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) ~~\$640-628~~ 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 (“SO₂”), 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;

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- 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:

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- 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

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1 financial stability of the regulated electric utility. The Company is committed to achieving
2 Net Zero Carbon Emissions by 2040 for all generating resources to meet customers' needs
3 and is well positioned to achieve this goal by continuing the efforts to support research and
4 development, technology solutions to enhance operational flexibility of a dynamic electric
5 system created by intermittent resources and demand-side management programs, and
6 gaining learnings from the development of the solar glidepath identified in the PCA.
7 Additionally, future learning opportunities pursued by the Company will help to accelerate
8 the pace of the clean energy transformation with a mix of technology solutions.

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

20 **SECTION I: IRP OVERVIEW**

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

22 A. Section 6t (1) of Act 341 required the Commission, within 120 days of the effective date
23 of the act and at least every five years thereafter, to commence a proceeding that, among
24 other things, establishes modeling scenarios and assumptions that each electric utility

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1 should include, in addition to the Company's own scenarios and assumptions, in
2 developing its IRP.

3 On July 31, 2017, the Commission initiated Case No. U-18418 to implement the
4 provisions of Section 6t (1) of Act 341. In its Order, the Commission directed the MPSC
5 Staff to file a proposal to establish parameters related to the IRP process in the docket no
6 later than August 31, 2017. The Order scheduled three public hearings in September 2017
7 and gave opportunity for written comments from any interested source to be submitted to
8 the docket through October 20, 2017. The Commission approved Michigan Integrated
9 Resource Planning Parameters on November 21, 2017, which included scenarios,
10 assumptions, and sensitivities that must be included in each utility's IRP. On February 18,
11 2021, the Commission issued an Order in Case No. U-20633 directing Consumers Energy
12 to include an additional scenario ("Carbon Reduction Scenario") inclusive of two carbon
13 sensitivities in the Company's 2021 IRP filing.

14 In addition, Section 6t (3) of Act 341 required the Commission to issue an order
15 establishing filing requirements, including application forms, instructions, and filing
16 deadlines for an IRP filed by an electric utility whose rates are regulated by the
17 Commission. On October 11, 2017, the MPSC issued an Order in Case No. U-15896, et
18 al requesting comments on draft IRP filing requirements and on draft alternative proposal
19 filing requirements applicable in IRP cases and CON cases to comply with Sections 6t and
20 6s of Act 341. The Commission issued an Order on December 20, 2017 in that proceeding
21 which adopted final filing requirements.

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1 **Q. Please explain the Company's 2018 IRP.**

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

11 At a high level the settlement agreement included:

- 12 • The approval of the Company's PCA as the most reasonable and prudent means
 13 of meeting the Company's energy and capacity needs over the 5-year, 10-year,
 14 and 15-year time horizons and a refresh of the evaluation is to be provided by
 15 the Company in a new IRP filing made by June 2021 to continue to show the
 16 plan is the most reasonable and prudent means of meeting the Company's
 17 energy and capacity needs;
- 18 • The pre-approval of costs for demand-side management programs in the first
 19 three years of the plan (2019-2022);
- 20 • The accelerated retirement of Karn Units 1 and 2 in 2023 and to seek recovery
 21 of the unrecovered book balance by no later than May 31, 2023;
- 22 • A Company-conducted retirement analysis of Campbell Units 1 and 2 which
 23 will be presented in the Company's 2021 IRP;
- 24 • A competitive bidding process to address future capacity needs of the Company
 25 during the IRP period and for determining the Company's PURPA avoided cost
 26 rates. The parties also agreed that the Company shall use a five-year outlook
 27 for determining capacity needs and that a PURPA capacity need does not exist
 28 for the Company if the Company is implementing its PCA as defined by the
 29 competitive bidding process;
- 30 • A 50% PPA and 50% utility ownership split of future supply-side capacity
 31 acquired through the competitive bidding process;

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- 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”),

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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

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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.

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

2 A. Leading indicators from across the United States identify potential risks to electric supply
 3 reliability as the electric industry shifts from traditional controllable generation (i.e. coal)
 4 to greater levels of intermittent and demand-side management programs. This is evidenced
 5 by MISO conducting workgroup sessions to design a resource adequacy construct better
 6 able to plan across all seasons in the MISO footprint to mitigate non-traditional peak
 7 demand concerns (i.e. winter months) and the traditional coincident peak occurring in the
 8 summer months of July and/or August. Additionally, the North American Reliability
 9 Corporation (“NERC”) issued its 2020 State of Reliability – An Assessment of 2019 Bulk
 10 Power System Performance¹ in July 2020 flagging continued risks of Electric Reliability
 11 Council of Texas not meeting its Planning Reserve Margin Requirements (“PRMR”).
 12 NERC identified the need to address system protection and system needs as electric utilities
 13 across the nation replace greater levels of controllable generation with dynamic
 14 uncontrollable technologies. Lastly, MISO has long indicated the potential of Zone 7 (the
 15 majority of Michigan’s lower peninsula) to be short in meeting its local resource needs the
 16 next five years due to the level of demand-side management programs and new planned
 17 resource builds not yet in the process of being constructed or operational. These changes
 18 and indicators are further discussed by Company witness Thomas P. Clark.

19 Electric supply reliability is a core necessity of any resource plan. The Company
 20 has an obligation to create a clean plan that de-risks its customers, the state, and the
 21 Company from the potential lack of resources necessary to meet energy and capacity needs

¹NERC’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

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1 during extreme weather events, the level of availability from intermittent resources and
2 demand-side management programs, and locating/bringing resources to the state of
3 Michigan rather than a reliance on new resource builds outside of the state. The Company
4 offers a plan that provides this and the flexibility to adapt its plan to the changing needs of
5 customers and the system with the ability to potentially create new jobs and revenue for
6 Michigan.

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

8 A. In the past two years the Company has seen three different sets of regulation at either the
9 state or federal level regarding climate change by way of legislation or executive targets.
10 At the federal level, the Biden Administration issued a goal to have a carbon free power
11 sector by 2035, economy-wide carbon neutrality by 2050, and to rejoin the Paris Climate
12 Agreement. The Paris Climate Agreement seeks to limit average global temperature to
13 2°C, and preferably 1.5° C. To reach the 2° C goal, global economy-wide greenhouse gas
14 emissions must reach net-zero by approximately 2070. To reach the 1.5° C goal,
15 greenhouse gas emissions must be reduced by 40-60% by 2030 and be net-zero by 2050.
16 Consistent with the 1.5° C goal, both the Biden Administration and Governor Whitmer (as
17 part of the MI Healthy Climate initiative) have announced net-zero by 2050 goals.
18 Additionally, Governor Whitmer set a near-term target of achieving a 28% reduction in
19 economy-wide carbon from a 2005 baseline by the year 2025 in Executive Directive 2020-
20 10. Prior to President Biden's and Governor Whitmer's targets being announced, the
21 Company made a public commitment to achieving Net Zero Carbon Emissions that
22 considers all sources of generation used to serve its customers (owned, contracted, and
23 market) by 2040, surpassing other target dates set by administrations at the time. The

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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?

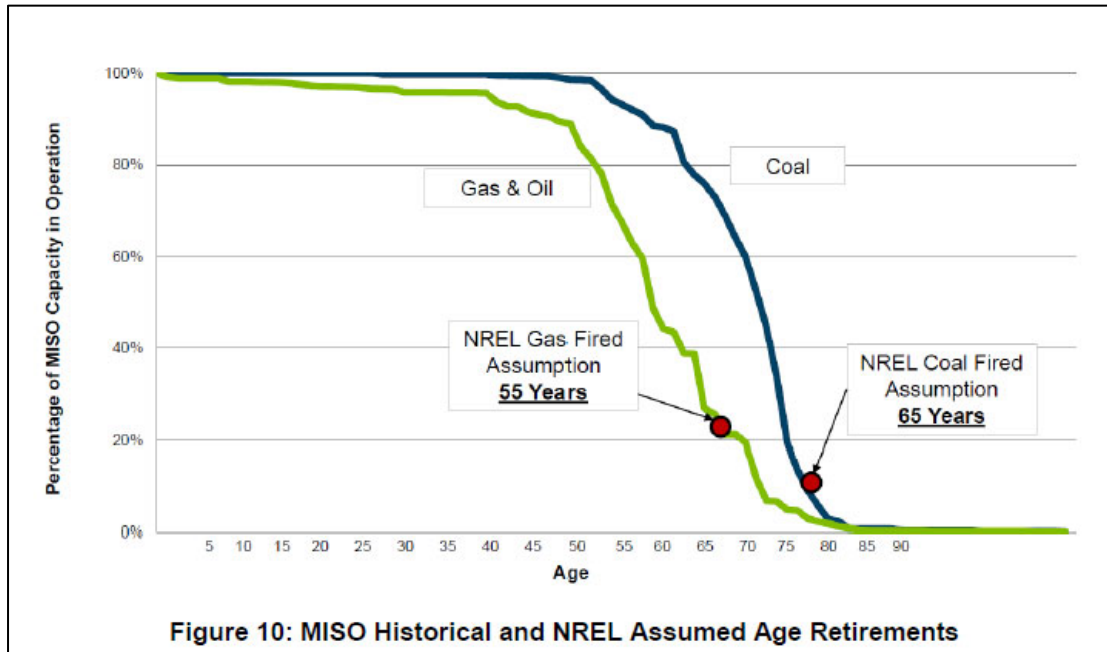
A. The age and operational performance of Campbell Units 1 and 2, which are coal units, and Karn Units 3 and 4, which are oil/gas peaking units, have provided a basis to reevaluate

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

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

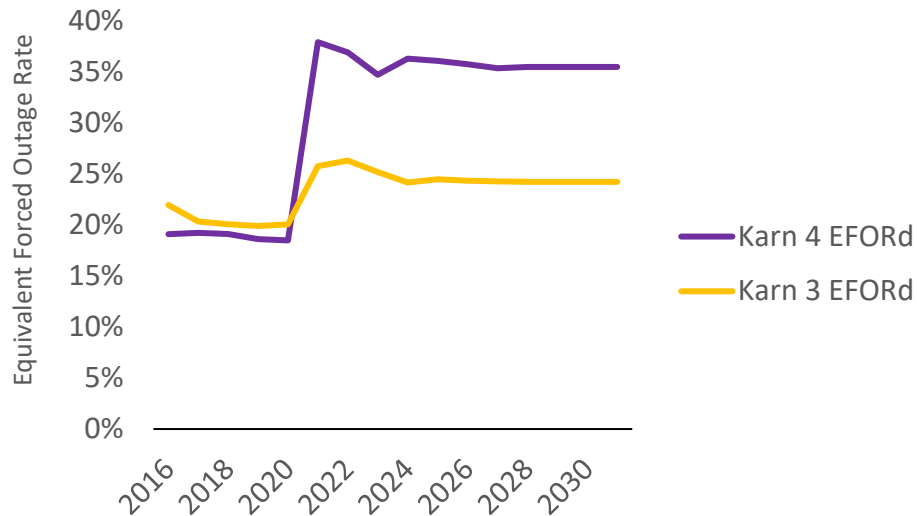


Karn Units 3 and 4 have had similar operational issues, as evidenced by the forced outage rate (“EFORD”) actuals starting in 2016 and the projected EFORD levels to 2031. Operational performance of the Campbell and Karn units is further discussed by Company witness Norman J. Kapala.

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

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Figure 2: Karn Units 3 and 4 EFORD Actual and Projections 2016-2031



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

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1 filing requirement and the corresponding location of responsive information in the
2 Company's filing. It should be noted that this exhibit is intended to direct a reviewer of
3 the Company's filing to information filed by the Company which addresses a certain filing
4 requirement and does not provide an exhaustive list of all information which may be
5 applicable to a certain filing requirement.

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

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

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

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

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

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

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

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

16 Company witness Teresa E. Hatcher compares the current REP assumptions to
17 those in the PCA and discusses the consistency between the IRP and the REP. The
18 comparison describes the renewable energy assumptions specific to utility-scale wind and
19 solar resources utilized in the IRP processes. Company witness Hatcher also discusses the
20 Renewable Portfolio Standards and renewable energy goals related to Public Act 342 of
21 2016. Additionally, she describes customer interest in renewables and energy saving
22 resources to meet sustainability goals.

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

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

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

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

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

20 Company witness Emily A. McGraw discusses the Company’s existing and
21 proposed demand-side management programs and describes the DR assumptions utilized
22 in the IRP process. In addition, Company witness McGraw explains the historical
23 performance of DR as pre-approved in the 2018 IRP and the levels of DR included as part

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1 of the PCA, and describes the costs associated with DR programs that will commence
2 within three years after a final order in this proceeding for which the Company is seeking
3 Commission approval for cost recovery, as provided by Section 6t of Act 341.

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

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

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

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

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

10 Company witness Jason R. Coker explains the financial assumptions used in the
11 IRP model, and provides an estimated customer rate impact of the PCA and an alternate
12 plan. Company witness Coker also discusses the necessary regulatory treatment and
13 recovery of the remaining unrecovered net book balances to retire Karn Units 3 and 4 and
14 Campbell Units 1, 2, and 3 before the end of their design lives (2031 for Karn Units 3 and
15 4 and Campbell Units 1 and 2, and 2039 for Campbell Unit 3).

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

22 Company witness Srikanth Maddipati explains the Company's proposed
23 adjustments to the FCM which provides an incentive for executing PPAs, as authorized by

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1 Section 6t (15) of Act 341, and the financial benefits of the proposed method of recovering
2 the remaining unrecovered net book balances for Karn Units 3 and 4 and Campbell Units
3 1, 2, and 3.

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

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

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

17 **SECTION II: IRP OBJECTIVES AND PRINCIPLES**

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

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

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- 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

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1 for extremes in shifting electric need throughout the year. It is of great importance for a
2 utility to create a plan agile and adaptable to dynamic changes in energy needs.
3 Additionally, the Company's flexibility to make economic market purchases of power,
4 reducing the Company's exposure to the volatility of the energy market.

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

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

13 **Planet**

14 From a *Planet* perspective, the Company must ensure the PCA meets Renewable
15 Portfolio Standards specified in Michigan law and compliance with applicable state and
16 federal environmental regulations (Commission objective ii). Transitioning to a clean and
17 lean resource portfolio positions the Company to achieve compliance with potential
18 environmental regulation that may be imposed in the future, such as carbon dioxide
19 emissions regulations, which reduces future financial risk to customers. The PCA must
20 also align with the Company's Clean Energy Goals, which extend beyond the compliance
21 level required by current law and illustrates the Company's deep commitment to protecting
22 the environment. The Company's Clean Energy Goal strives to be coal free and set a

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1 course for reaching Net Zero Carbon Emissions for all generating sources used to meet
2 customer needs by 2040.

3 **Prosperity**

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

19 Furthermore, a supply plan that is modular lessens customer rate impact as it
20 provides flexibility to adjust to changes in technology cost, electric demand, or the business
21 environment. This approach is a departure from the traditional utility model of pursuing
22 new large, centralized generation projects to realize economy of scale benefits, which can
23 result in the risk of inflexible supply, particularly when actual demand falls short of

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1 forecasted demand. This can be addressed with a lean portfolio that involves reasonable
2 and cost effective EWR (Commission objective vii). A modular approach provides a
3 scalable supply portfolio that minimizes potential for surplus capacity, diversifies supply
4 resources (Commission objective vi), insulates the Company and its customers from
5 commodity price risks, and protects against high customer rates (Commission objective v).

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

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

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

12 Second, the Company had to develop an analysis regarding the accelerated
13 retirement of the baseload coal units and the oil/gas peaking units. This analysis was
14 needed to support Company planet goals to exit coal faster, as well as the goals of the Biden
15 Administration and Governor Whitmer, while maintaining a similar or improved pace of
16 solar, battery, and demand-side resource expansion and create a path forward to achieving
17 Net Zero Carbon Emissions by 2040 for all sources used to serve customers. As part of
18 the settlement agreement approved by the Commission in Case No. U-20165, the Company
19 was also required to perform an accelerated retirement analysis of Campbell Units 1 and 2
20 which specifically examined the potential retirement of those units in isolation and
21 together, in years 2024, 2025, 2026, and 2028, as well as the continued operation of the
22 units through their end-of-design lives in 2031. The accelerated retirement of Campbell
23 Unit 3 was included in the analysis after leading indicators in the Campbell Units 1 and 2

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1 results identified potential solutions to exit coal while continuing to serve customers
2 reliably. Additionally, the Company examined the accelerated retirement of Karn Units 3
3 and 4 as early as 2023 and no later than 2025. By accelerating retirement of these units at
4 or near the same year as the currently approved retirement year for Karn Units 1 and 2 (i.e.
5 2023), the communities around the Karn generation site are better positioned to create
6 greater redevelopment opportunities at a quicker pace, a quicker transition for Company
7 co-workers, and to mitigate operational performance risks for customers by replacing with
8 resources able to provide capacity and greater levels of energy production throughout the
9 year.

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

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

21 Fifth, the Company sought to continue to seek competitive pricing for supply
22 options that mitigates future cost risks for customers. The Company proposes the
23 continuation of the currently approved competitive procurement process, with certain

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

19 Sixth, because the Company is proposing to continue the competitive procurement
20 process with modifications, the Company sought to continue the FCM. The Company
21 proposes the FCM be applied as a fair return on PPAs at an adjusted pre-tax Weighted
22 Average Cost of Capital. A PPA incentive helps align the Company's and customer
23 interests by removing potential bias toward utility-owned assets. This alignment of

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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.

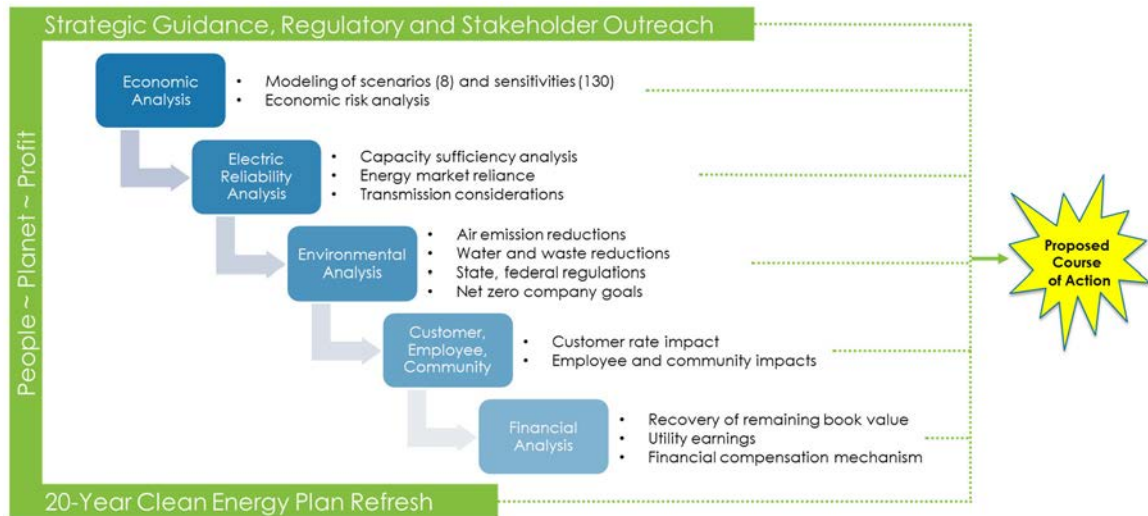
SECTION III: IRP PROCESS

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.

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Figure 3: Integrated Resource Plan Process and Key Analysis



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

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1 thinking for consideration in the creation of the IRP. These outreaches gave an opportunity
2 to address their concerns and continue to understand the diverse perspectives of meeting
3 future capacity and energy needs.

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

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

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

21 To determine the capacity sufficiency of a resource, the Company utilized a type of
22 Loss of Load Expectation (“LOLE”) Study as required in the settlement approved in the

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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 capacity 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

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1 significant risk to the Company in serving its customers reliably. As an example of this,
2 the Alternate Plan on average relies on 32% of the CIL capability while the PCA relies on
3 17% of the total import capability. Instead, if, on a typical day, a portfolio indicates
4 customer demand is predominantly served by the Company's existing and planned
5 resources, like the PCA, this indicates minimal risk of serving customers reliably. For
6 energy market reliance a year-by-year assessment of energy supply is evaluated to
7 determine the level of market purchases. The greater the percent of market reliance on
8 energy the greater the exposure to increasing costs due to volatility in the market.

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

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

17 A. The Company evaluates environmental benefits of a resource plan by assessing impacts to
18 air emissions, water usage, waste creation and/or elimination, and land impacts due to new
19 resource builds or potential for re-purposing. The air emissions evaluated by the Company
20 include carbon emissions from a 2005 baseline, NO_x, SO₂, particulate matter, and mercury.
21 The water usage/savings are based upon annual gallons used for cooling systems of thermal
22 units. The creation or reduction of waste is based upon annual coal ash production. Land
23 use is a qualitative measure of the ability to redevelop or repurpose coal asset site locations

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1 and the siting of new resource builds benefiting the environment. Additionally, an
2 assessment is made on the state and federal regulatory proposals and requirements
3 impacting a regulated electric utility's resource plan such as Executive Directive 2020-10
4 issued by Governor Whitmer on September 23, 2020 setting a goal to reduce carbon
5 emissions from the 2005 baseline by 28% economy-wide by the year 2025. Finally, the
6 Company compares resource plans to understand their ability in achieving the Company's
7 planet goals. The Company had a prior goal from the 2018 IRP to be coal free by 2040
8 and reduce carbon emissions by 80% from a 2005 baseline. The Company later evolved
9 this metric to a Net Zero Carbon Emissions by 2040 goal for all sources of generation; a
10 higher standard to achieve than only evaluating Company-owned assets. The direct
11 testimony of Company witness Breining further explains the Environmental Impact
12 Analysis.

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

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

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1 new fossil assets. The employee and community impacts are further detailed by Company
2 witness Kapala. The evaluation of vulnerable communities is further detailed in the direct
3 testimony of Company witness Breining.

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

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

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

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

21 **Q. Please describe the public outreach efforts.**

22 A. For the public and the Company's customers, four virtual outreach session events were
23 held, recorded, and posted to the Company's website for public consumption. The virtual

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

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

14 **Q. Please describe the technical workshops.**

15 **A.** For those expected to be highly involved in the technical aspects of the IRP, a series of
16 technical workshops were created to address questions and obtain detailed insights and
17 requests that could be incorporated into the analytical portion of the IRP. The Company
18 invited participants for these workshops based on the parties that participated in the
19 Company's last electric rate cases and 2018 IRP case, Case No. U-20165. The first
20 technical workshop session was held in-person on December 12, 2019 in Jackson,
21 Michigan and virtual technical workshop sessions were held on May 28, 2020 and January
22 28, 2021. The technical workshops provided an opportunity for:

- 23 1) The Company to inform and educate stakeholders on the components of an IRP,
24 the analytical approach, and preliminary results of the analysis of the IRP;

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1 2) Stakeholders to ask the Company clarifying questions; and

2 3) The Company to solicit feedback from stakeholders, with documented
 3 comments for the Company to consider in the development of the IRP.

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

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

- 8 • Technical Workshop 1 (December 12, 2019): An initial kick off to develop this
 9 IRP. Content covered basic principles and objectives, new items being
 10 incorporated into the analysis, schedule, capacity position, and a preview of
 11 scenarios, sensitivities, and assumptions;
- 12 • Technical Workshop 2 (May 28, 2020): Shared specific information on the
 13 approach to public outreaches, a refresher on the IRP process, a refresh of
 14 scenarios and sensitivities being evaluated, major data assumptions, and
 15 approach to stochastic risk analysis; and
- 16 • Technical Workshop 3 (January 28, 2021): Shared progress to date on
 17 stakeholder outreach effort, a refresher of the IRP process, preliminary selection
 18 of resources in the analysis, description and approach to electric supply
 19 reliability, and approach to risk analysis.

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

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

23 A. As part of the IRP development process, the Company engaged early on with the local
 24 transmission owner represented by METC/ITC to support evaluation of transmission
 25 system effects for cases of accelerated retirement, generation additions, network upgrade
 26 costs, and interconnection costs. The Company and METC/ITC met on a frequent basis to
 27 discuss the request for analysis, scope, assumptions, and deliverable dates. The analysis
 28 provided by METC/ITC was incorporated as part of the analysis to support the

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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

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1 against an Alternate Plan that represents a refreshed version of the 2018 IRP for
2 affordability, electric supply reliability, reduction to environmental impacts, and resiliency
3 to risk parameters to ensure the PCA represented a better IRP for Michigan.

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

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

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

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

20 A. This IRP includes four scenarios required by the MPSC: (i) Business As Usual (“BAU”)—
21 (current conditions continue into the future); (ii) Emerging Technology (“ET”)—(current
22 conditions continue except renewable resources, EWR, and DR become materially less
23 expensive); (iii) Environmental Policy (“EP”)—(30% reduction in carbon by 2030 and

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1 materially less expensive renewable resources); (iv) Carbon Reduction—(replica of the
2 required EP scenario at 1.5% year-over-year load growth with the Company's PCA forced
3 into that scenario, optimized and then evaluated for achieving a 28% and 32% reduction in
4 carbon emissions from 2005 by 2025). In addition to these four scenarios, there were a
5 collection of sensitivities required to be evaluated on each scenario. The Company's
6 scenarios and sensitivities are aligned with the scenarios and sensitivities mandated by the
7 Commission's November 21, 2017 Order in Case No. U-18418. The Commission later
8 included the Carbon Reduction scenario in the IRP scenarios and sensitivities in its
9 February 18, 2021 Order in Case No. U-20633.

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

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

18 In support of these scenarios and sensitivities, assumptions necessary to translate
19 the scenarios and sensitivities into models were developed. This included assumptions
20 such as, but not limited to, customer demand forecasts, fuel cost forecasts, technology
21 characteristics and costs, and program levels for EWR and DR. The Company also
22 performed screening evaluation producing a set of resource options for consideration in

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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

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1 in the near term, the Company conducted an RFP for existing gas units easily transferrable
2 to Zone 7 or in Zone 7. The RFP was administered by an independent third party, Charles
3 River Associates (“CRA”). This RFP process is further discussed by Company witness
4 Troyer. The Company then examined the resource plans with and without the inclusion of
5 CRA’s RFP results to determine the reasonableness of the assumptions upon which they
6 were based. Furthermore, the Company examined these resources to determine if they
7 aligned with the planning objectives. Resources based upon reasonable assumptions and
8 alignment with the planning objectives were included in the PCA in amounts necessary to
9 meet capacity and energy needs.

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

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

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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.

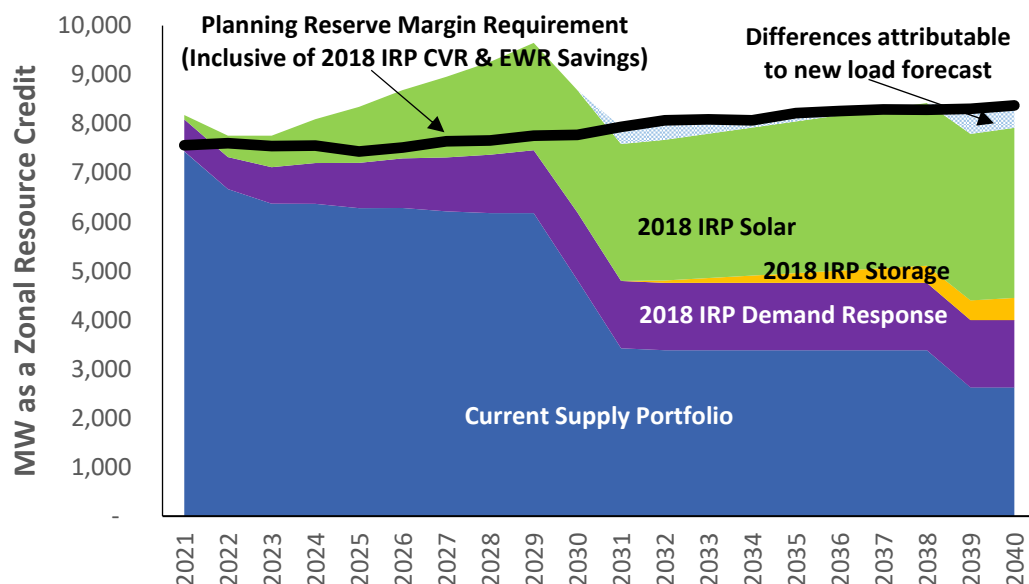
The Company currently owns 5,945 MW of installed capacity located within Michigan and within MISO Zone 7. Supply-side resources owned and operated by the Company include five coal-fueled generating units, two gas-fueled combined cycle plants, a pumped storage plant, several gas-fueled combustion turbines, 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.

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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



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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.

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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

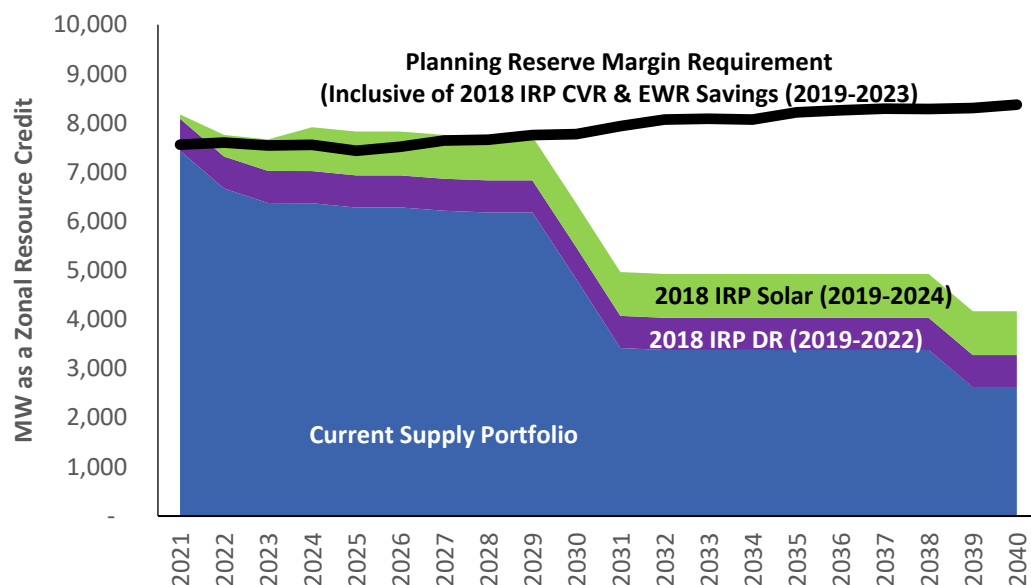
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case, Case No. U-20134. Planned DR incremental to these levels were removed in years 2023 through 2040;

- 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.

Figure 5: Modified Base Case Balance of Supply and Demand to Meet PRMR



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

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- 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.

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SECTION V: PROPOSED COURSE OF ACTION

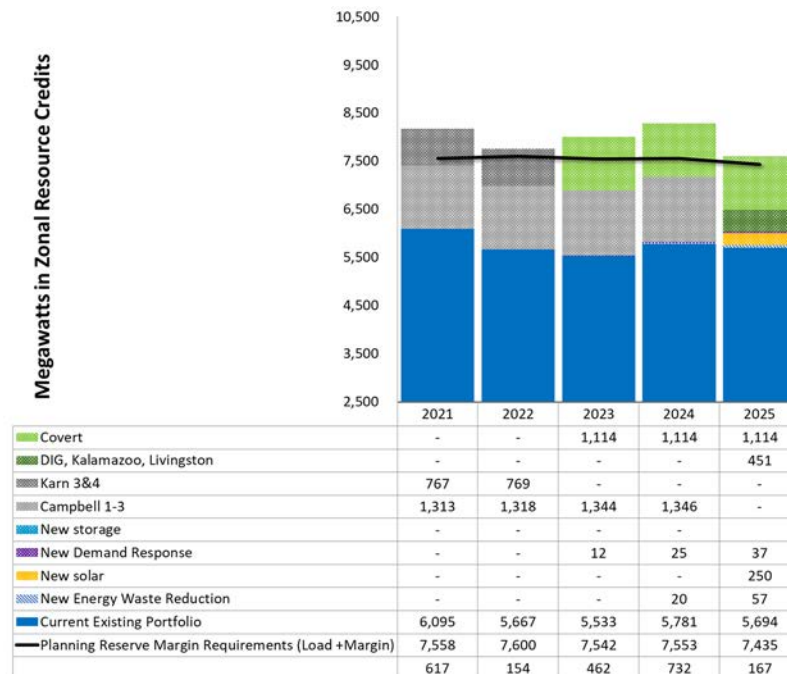
Q. Please describe the components of the Company's PCA.

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



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- EWR and CVR
 - o 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
 - o 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
 - o 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)
 - o 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)
 - o 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)
 - o 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)
 - o 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

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

- Storage:

- o 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

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1 as a MISO market participant are this in place. Upon the purchase of the Covert Plant by
2 the Company, the Covert Plant would transfer from PJM to MISO Zone 7 providing an
3 additional 1,114 ZRCs of capacity and reliability to the Company's customers and
4 Michigan.

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

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

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

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

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

19 As explained in the direct testimony of Company witness Battaglia, the DIG Plant
20 is a combined cycle natural gas-fired electric generating plant commissioned in 2001
21 (includes a 160 MW simple cycle natural gas-fired generating unit in 1999) with a nominal
22 nameplate capacity of 770 MW located in Dearborn, Michigan. The DIG Plant is currently
23 operating in Michigan as a market participant in MISO. DIG also has three natural

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1 gas/blast furnace gas boilers that are partially fired with waste gas from AK Steel, an
2 industrial company located adjacent to the DIG Plant. The DIG Plant has three gas turbines
3 with two of the turbines operating in a combined cycle mode with a single steam turbine.
4 The DIG Plant's availability has averaged 90% for the past three years. Furthermore, as
5 explained in the direct testimony of Company witness Gallaway, who discusses the fuel
6 supply arrangements for the DIG Plant, the site receives natural gas fuel from DTE Gas
7 Company.

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

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

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

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

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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 Kvorciak, 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.

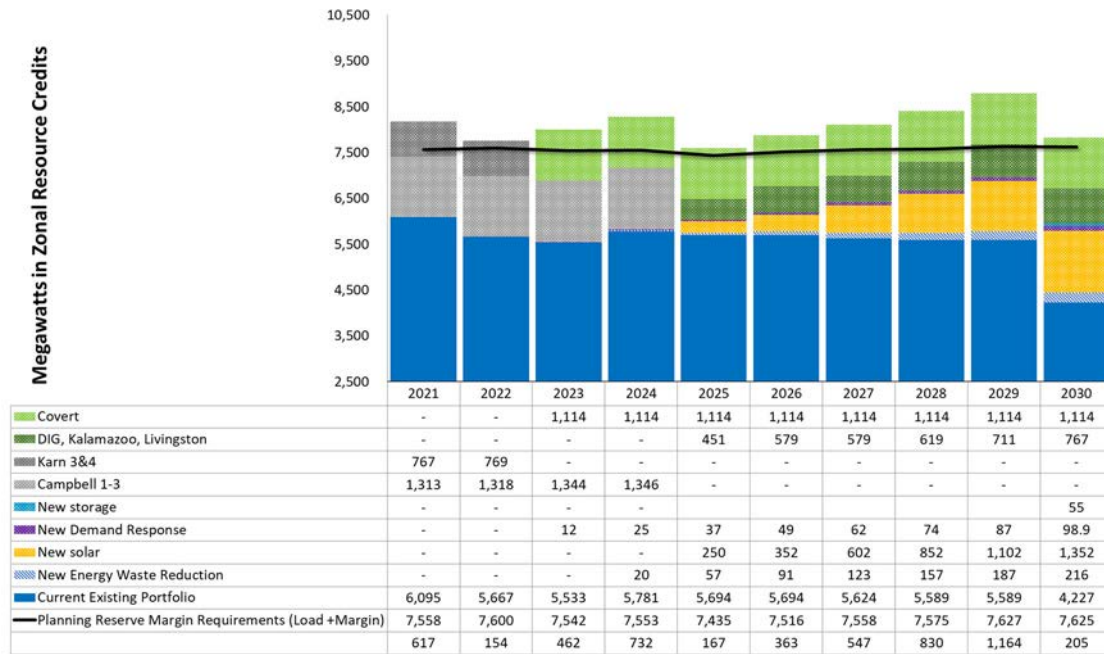
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1 **Q. Please provide an overview of the 10-year plan.**

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

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Figure 7: Proposed Course of Action – 10-Year Plan



- 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:

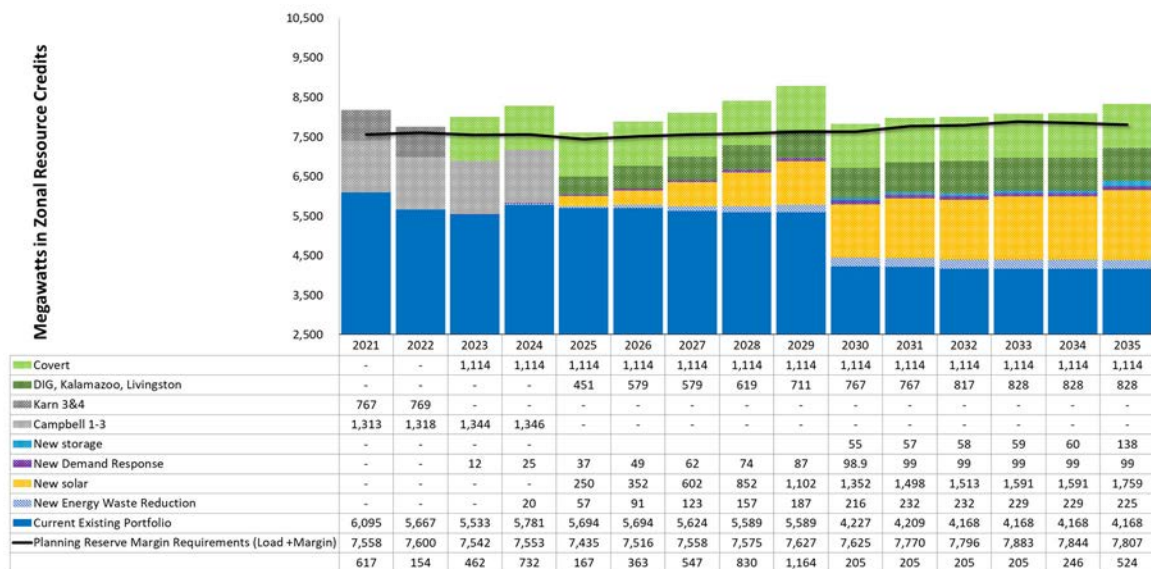
- o 58 MW (55 ZRCs) of batteries is added in the year 2030. This amount represents one ancillary services market battery and is the beginning of a glide path of batteries to serve forecasted demand needs in the year 2040. Details about the battery are provided in the direct testimony of Company witnesses Walz, Battaglia, and Washburn.

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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



- 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;

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- 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.

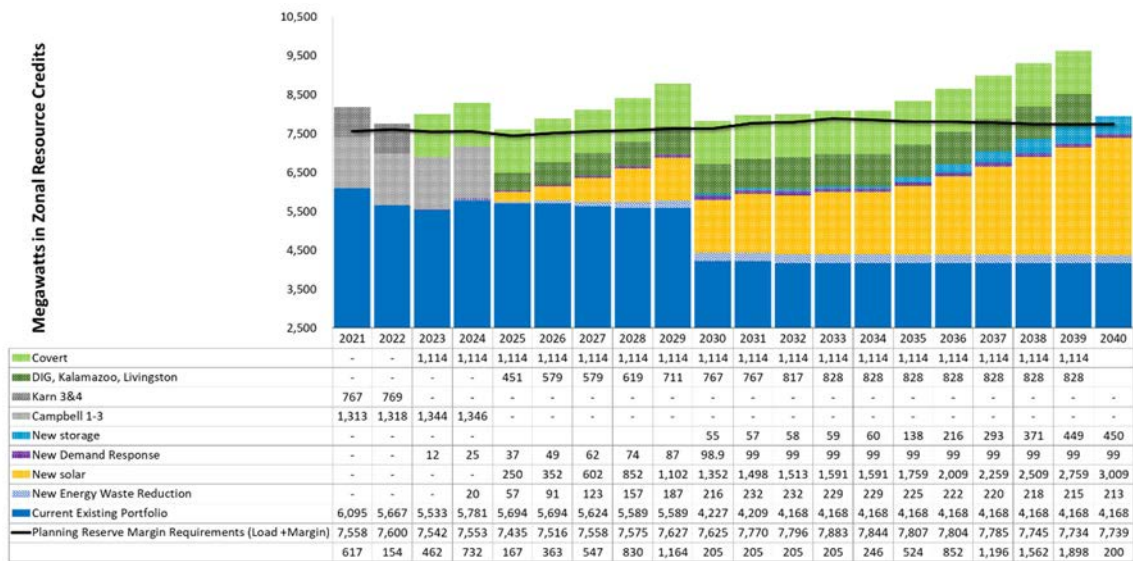
Q. Please provide an overview of the 20-year plan.

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

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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.

Figure 9: Proposed Course of Action – 20-year Plan



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

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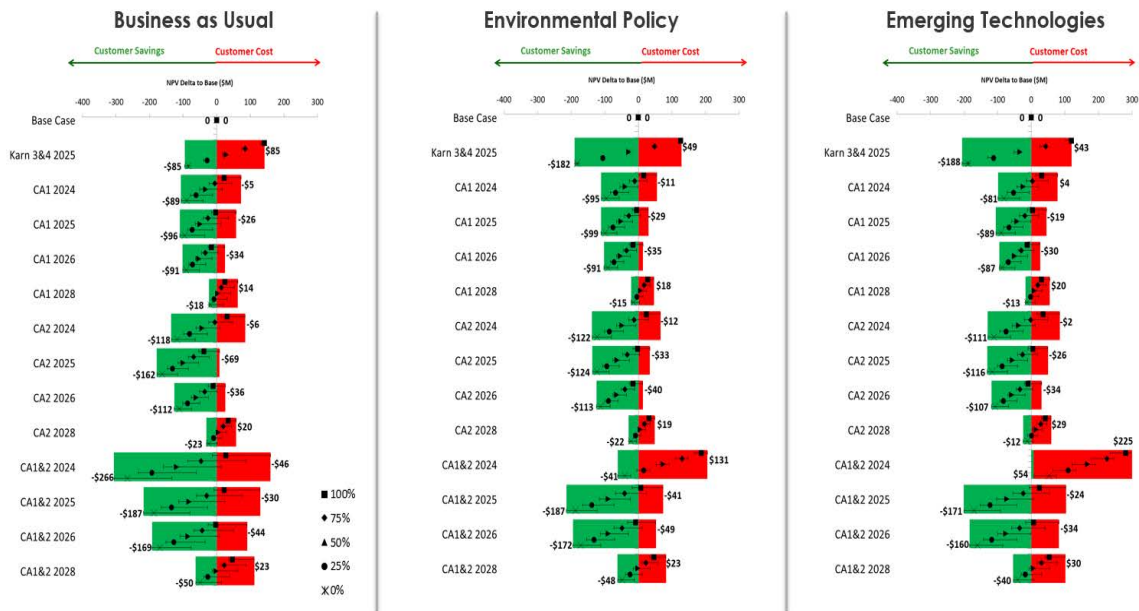
1 Karn Units 3 and 4 in years 2023 and 2025 and Campbell Units 1 and 2 in years 2024,
2 2025, 2026, and 2028 in isolation and together. Additionally, the Company evaluated each
3 of the optimal replacement plans for these cases against the base continued operations case
4 under a cost benefit analysis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

6 The analysis re-examined the ongoing capital expenditures and O&M expenses
7 necessary to continue operation of each of the units between now and the expected design
8 lives. Additionally, ongoing capital expenditures and O&M expenses were analyzed for
9 the accelerated retirement years designated in the 2018 IRP settlement agreement for
10 Campbell Units 1 and 2, the retirement of Campbell Unit 3 in 2025, and Karn Units 3 and
11 4 retiring in 2023 and 2025. The above referenced capital expenditures and O&M expenses
12 are detailed in the direct testimony and exhibits of Company witnesses Kapala and
13 Breining.

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

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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.

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

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

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

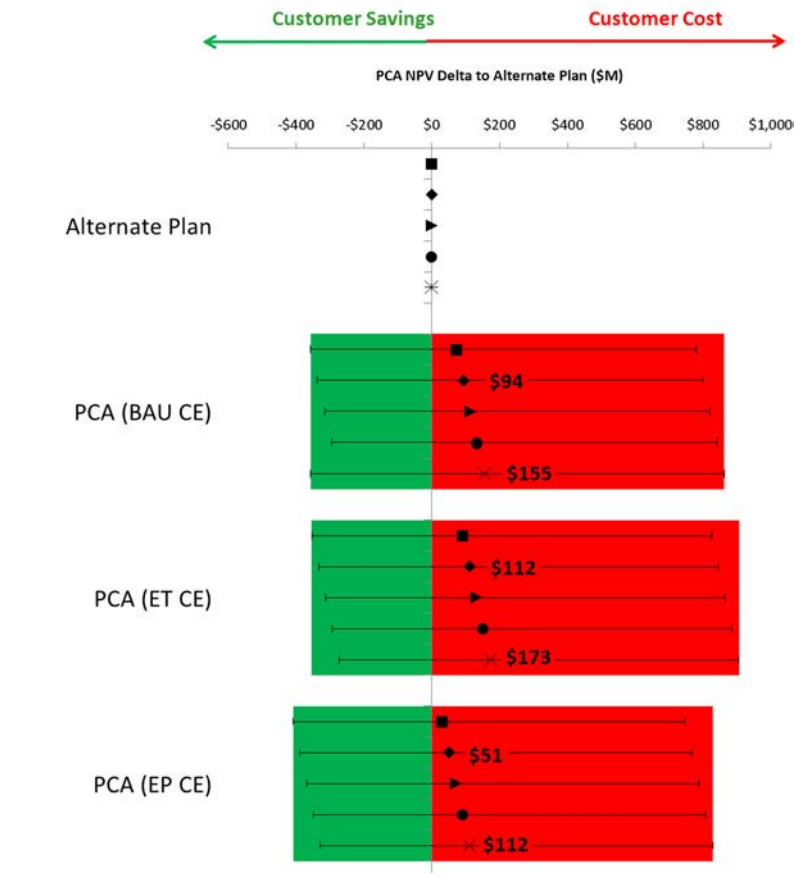
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Campbell Units 1 and 2 together and consider the accelerated retirement of Campbell Unit 3.

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.

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Figure 11 Revised: 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

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1 of solar, batteries, and demand-side management programs in a manner similar to the 2018
2 IRP.

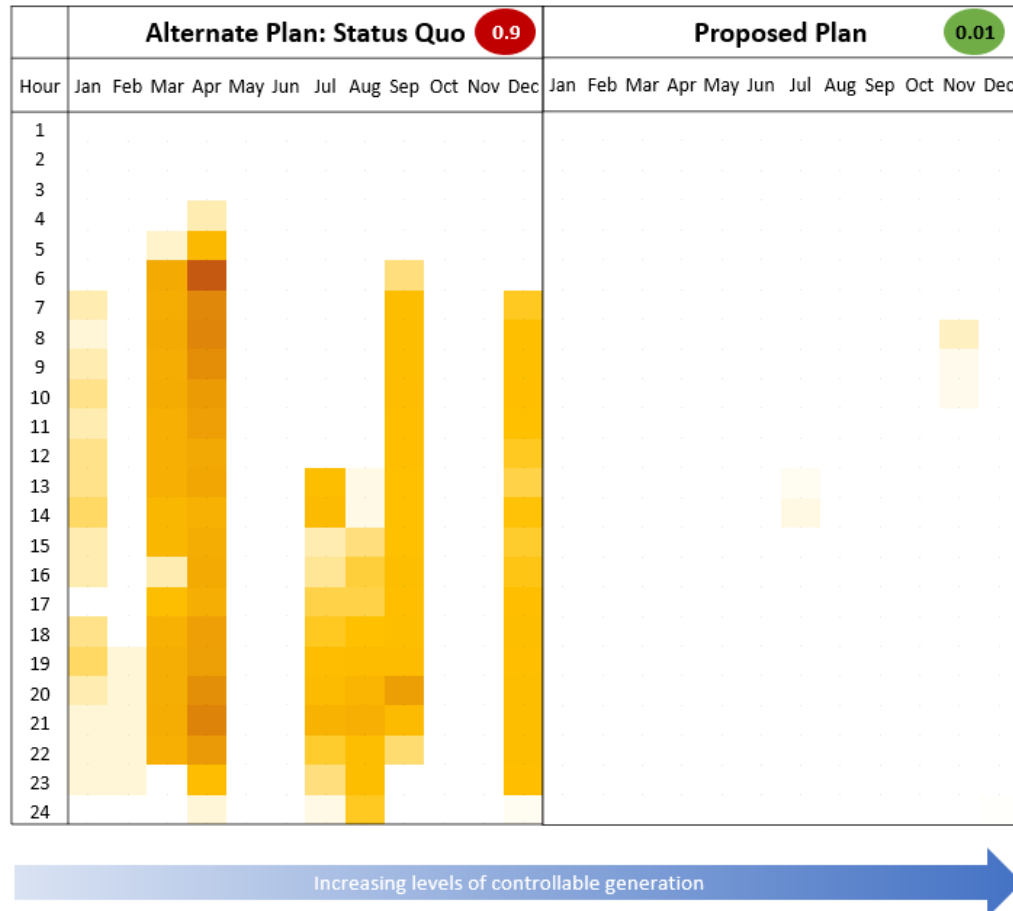
3 **Q. Please provide a summary of the Company's electric supply reliability assessment**
4 **results.**

5 A. A capacity sufficiency assessment evaluated electric supply reliability concerns in the year
6 2032 to identify electric supply reliability issues. The year 2032 is used as a point in time
7 when the Company makes a transformational change in its resource mix. This
8 transformational change replaces nearly 3,500 MW of controllable generation with
9 intermittent resources (i.e. 5,000 MW of solar) and demand-side management programs
10 (nearly 2,000 MW of peak load reduction). This is 38% controllable generation owned by
11 the Company replaced with intermittent and demand-side programs. The results of the
12 assessment on the refreshed 2018 IRP case identified consecutive hours and days
13 throughout the year, particularly in the winter, when the Company would not be sufficient
14 in supplying customers with electricity, even when full access to 3,200 MW market
15 purchases (i.e. the CIL) is available. These shifts are recognized by the industry, as
16 indicated by MISO's efforts to change to a seasonal market construct and evaluating
17 resource needs beyond a summer peak period. Furthermore, while the CIL is used as a
18 resource fully available to Consumers Energy for modeling purposes – it is not. The day
19 to day use of this resource up to 3,200 MW is not a reasonable or prudent solution to
20 mitigating electric supply reliability issues and should not be used as resource to
21 consistently serve customers every hour of every day throughout the year. Figure 12
22 illustrates a heat map of when the study identifies a frequency of not serving customer

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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

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1 deficiency in supply, however due to its short-lived charging and discharge cycles and the
2 economic neutrality of the cost to charge to the value of discharging, batteries were not
3 adequate in closing the reliability gaps across all hours and continue to draw on carbon
4 emitting resources to charge which inhibits the ability to achieve reductions in carbon
5 emissions for all sources of energy. The accelerated retirement of Campbell Unit 3 in the
6 earlier 2030s or in 2025 would further exacerbate the reliability issues if the replacement
7 plan is overly reliant on renewable/intermittent resources and demand-side management
8 resources.

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

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

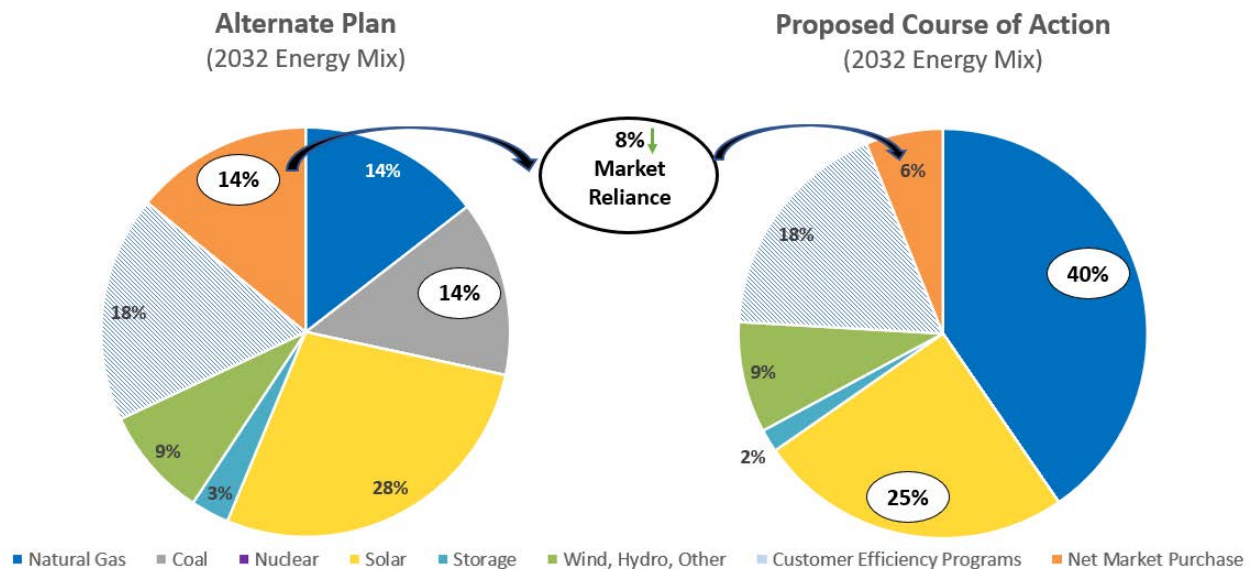
17 **Q. Did the Company evaluate any additional factors in its electric supply reliability**
18 **assessment?**

19 **A.** Yes. As a part of the electric supply reliability assessment the Company evaluated the
20 level of energy market reliance of the resource plan. In comparing the year 2032 of the
21 Alternate Plan to the PCA, the Company found that the purchase of the existing gas units
22 cut the energy market reliance by 50%. That reduces the Company's exposure to market
23 price volatility and provides the Company with the ability to choose, in the best interest of

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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.

Figure 13: Energy Mix for the Alternate Plan versus the PCA in the year 2032



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

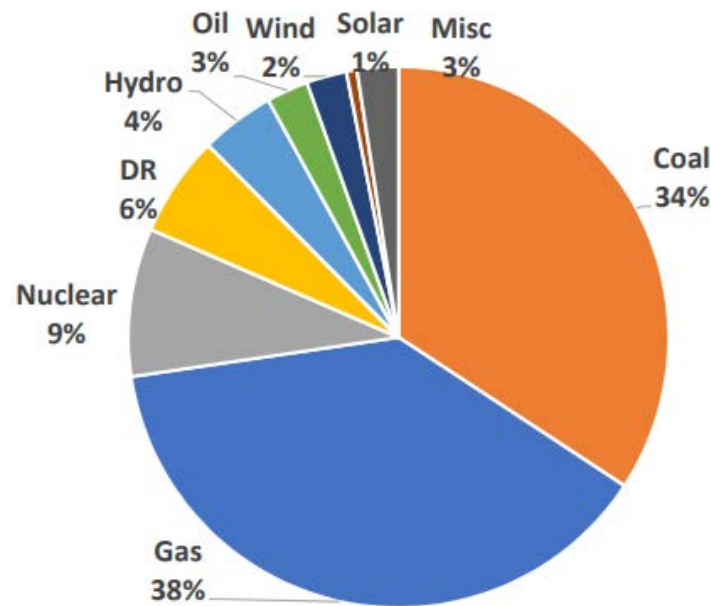
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1 Company's NPV analysis for accelerated retirement cases and the PCA. The details of the
2 analysis are described in the direct testimony of Company witness Scott.

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

5 A. The environmental impact assessment for the accelerated retirement of Karn Units 3 and 4
6 and Campbell Units 1 and 2 showed positive impacts for carbon emissions reductions to
7 further close the gap to achieve greater than 90% carbon reductions of the Company's
8 owned generation resources and the Company's Net Zero Carbon Emissions for all sources.
9 Whether the Company owns or purchases from the market makes zero to minimal changes
10 in closing the gap to Net Zero Carbon Emissions. This is due to the need for market
11 purchases to serve customer demand under a heavy renewable plan or to generate the
12 energy for customers through traditional controllable generation. The purchase of the
13 existing gas units helps to reduce the need for market purchases and in turn offsets potential
14 carbon emissions being generated by coal resources in the market. As shown in Figure 14,
15 the MISO market is made up of 34% coal and becomes a major source of energy to supply
16 customers when renewable and demand-side resources are unavailable due to lack of sun,
17 wind, and customer participation. Additionally, there were reductions in water, waste, and
18 other air criteria pollutants identified with accelerated retirement of these units. The direct
19 testimony of Company witness Breining further describes the results. Additionally,
20 whether the Company purchased the Covert, DIG, Kalamazoo, and Livingston plants or
21 not, these facilities exist and operate today and allow the Company to retire Campbell Units
22 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



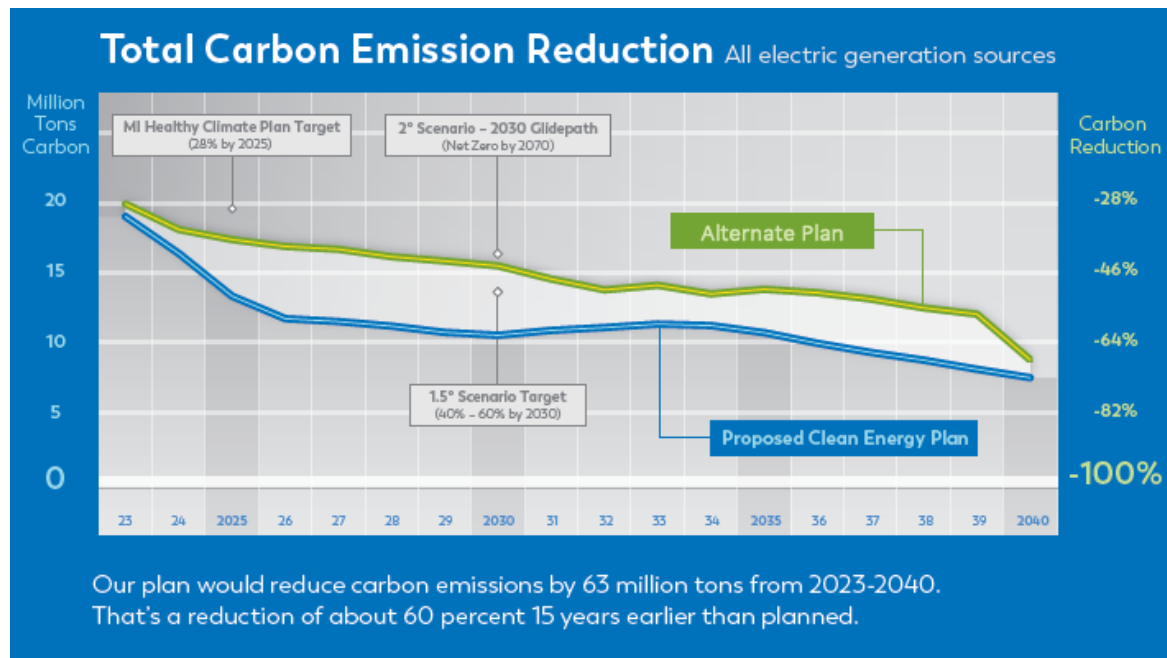
1 The Alternate Plan (status quo 2018 IRP) relies heavily on market purchases and
 2 continued investments in the coal units to allow for continued operations through 2039.
 3 The PCA reduces carbon emissions when compared to the Alternate Plan by 63 million
 4 tons, which is eliminating about 5.5 years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

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

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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

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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;

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(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.

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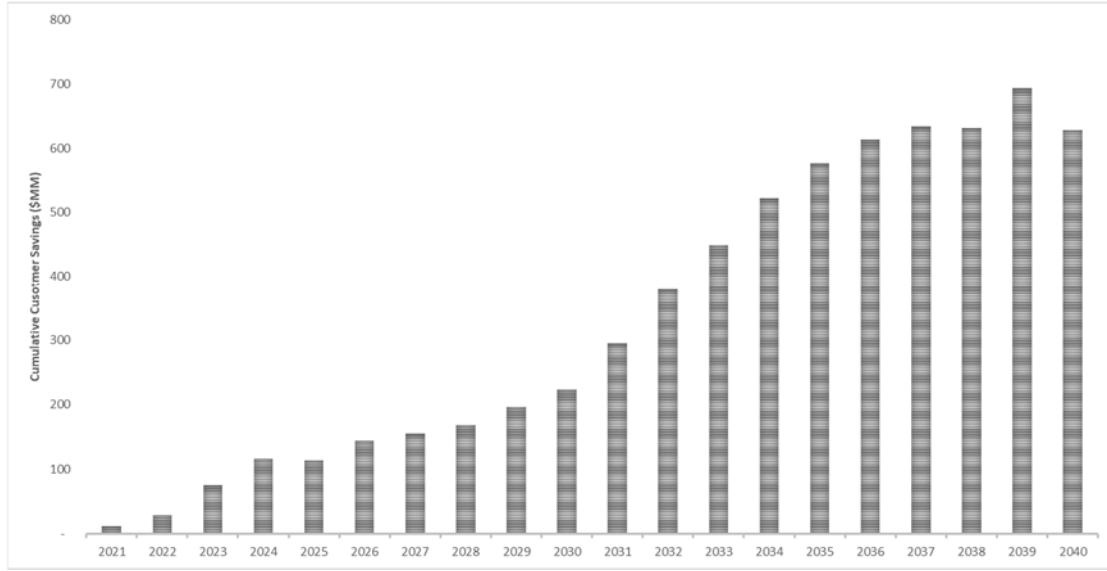
1 **Q. Please provide a summary of the Company's customer rate impacts assessment**
2 **results.**

3 A. The customer rate impact assessment for the accelerated retirement of Karn Units 3 and 4
4 and Campbell Units 1 and 2 showed a potential for customer savings (NPV) for each
5 accelerated retirement year across the CE scenarios assessed under a working assumption
6 that the remaining net book balance would be recovered as a regulatory asset through the
7 current design life of the unit. A reduction in the CAGR was identified for these cases as
8 well, however, in times of retiring an asset, customers experience high year-over-year rate
9 increases (i.e. highest 0.72%). In the development of the PCA, the rate impact associated
10 with the accelerated retirement of Campbell Unit 3 was incorporated into the analysis
11 comparing the Alternate Plan to the PCA. As discussed by Company witness Coker, the
12 PCA shows an NPV decrease in the incremental revenue requirement of about \$300 million
13 through 2040 and a cumulative savings of approximately ~~\$640~~628 million in 2040.

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

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Figure 16 Revised: Projected Cumulative Customer Savings – PCA versus Alternate Plan



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:

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- 1) ~~\$640-628~~ 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?

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1 A. Yes, it does. From a *People* perspective, the PCA's reliance upon demand-side
2 management resources and renewable generation supports compliance with the Company's
3 Clean Energy Goal, reduces waste, enhances reliability, keeps bills affordable, and aligns
4 with stakeholders' desire for evolution of the Company's resource portfolio. The Company
5 has demonstrated its commitment to communities and employees affected by past
6 retirement decisions and is committed to do the same with the decision to retire Karn Units
7 3 and 4 in 2023 and Campbell Units 1, 2, and 3 in 2025. The PCA is shown to provide the
8 necessary capacity and energy to reliably serve hourly and anticipated peak electric load
9 plus PRMR in all seasons through the study horizon with the purchase of the Covert Plant
10 and the DIG, Kalamazoo, and Livingston plants. The modular nature of the PCA created
11 by the continued build of solar, batteries, and demand-side management programs further
12 enhances reliability through reduced exposure to failures in energy transmission and
13 generator outages. Finally, the Company anticipates no expected detrimental
14 socioeconomic impacts, such as employment, for the local region of the Covert Plant and
15 DIG, Kalamazoo, and Livingston plants proposed to be purchased as part of the PCA.

16 From a *Planet* perspective, the PCA is in full compliance with all environmental
17 regulations and mitigates future financial risks of potential environmental regulation on
18 fossil fuel generation. The PCA aggressively reduces waste, increases solar and battery
19 generation, eliminates over 60 million tons of carbon from the environment, exceeds state
20 targets and the Paris Climate Agreement targets, eliminates 3 billion cubic yards of ash
21 waste, eliminates use of 220 billion gallons of fresh river and lake water, and reduces
22 emissions of criteria pollutants (SO₂, NO_x, mercury, and particulate matter).

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

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

13 **SECTION VI: DESCRIPTION OF SIGNIFICANT PROPOSALS**
14 **AND SUMMARY OF REQUESTED RELIEF**

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

17 **A.** As discussed above, the Company selected a bid for the Covert Plant and a bid for the DIG,
18 Kalamazoo, and Livingston plants as a result of an existing gas plant RFP issued January
19 2021. The Company's PCA proposed in this case includes the Covert, DIG, Kalamazoo,
20 and Livingston plants and the assumption that the Company will accelerate the retirement
21 of Karn Units 3 and 4 in 2023 and Campbell Units 1, 2, and 3 in 2025. The extensive
22 evidence provided by the Company in this case establishes that the Company's proposed
23 PCA, which includes the purchase of the aforementioned resources, represents the most
24 reasonable and prudent means of meeting the Company's energy and capacity needs and

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1 therefore, the PCA should be approved. If the Company's PCA is approved by the
2 Commission, the Company intends to go forward with the purchase of the aforementioned
3 plants and requires the approval of the costs to purchase the Covert Plant and the DIG,
4 Kalamazoo, and Livingston plants, pursuant to MCL 460.6t, in this case.

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

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

23 The Covert, DIG, Kalamazoo, and Livingston plants represent existing electric generation
24 facilities for which the Commission is permitted to approve the purchase price under the
25 law and the Company will incur the costs to purchase those plants within the three years
26 after the Commission's expected order approving this IRP on June 27, 2022 (i.e., by May
27 31, 2023 for the Covert Plant and by May 31, 2025 for the DIG, Kalamazoo, and Livingston
28 plants). Therefore, the Company is requesting Commission approval of the acquisition and
29 purchase costs of \$815 million for the Covert Plant and \$530 million for the DIG,
30 Kalamazoo, and Livingston plants, in the manner described in the Company's direct

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1 testimony and exhibits, as reasonable and prudent for cost recovery purposes pursuant to
2 MCL 460.6t.

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

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

16 **A.** The Company requests approval of the selection and proposed purchase of the DIG,
17 Kalamazoo, and Livingston plants, as a result of a competitive solicitation, which are
18 owned by subsidiaries the Company's affiliate CMS Enterprises, as compliant with the
19 Code of Conduct. The competitive solicitation also complied with FERC standards for
20 determining that an acquisition involving an affiliate will not adversely affect competition
21 and is consistent with the public interest as it satisfied the four principles – Transparency,
22 Definition, Evaluation, and Oversight – of FERC's solicitation guidelines. The purchase
23 price for the Company's acquisition of the DIG, Kalamazoo, and Livingston plants from

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1 CMS Enterprises reflects a fair market price for the assets, and is lower than the Company's
2 embedded cost of capacity. The transaction was part of the Company's 2021 competitive
3 solicitation that was independently administered. The use of an independent administer
4 allowed for an independent, fair, and transparent solicitation. It is under this process that
5 CMS Enterprises was selected as an economical and fair market bid. Since the contract
6 price is lower than the Company's fully embedded capacity costs, the Company's selection
7 and proposed purchase of the plants complies with the Code of Conduct.

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

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

20 **A.** As detailed in the direct testimony of Company witnesses Watkins and Coker, the
21 remaining net book balances of Karn Units 3 and 4 and Campbell Units 1, 2, and 3 are
22 significant and valued at over \$1.5 billion. A foundational component of the Company's
23 PCA is the approval of the Company's proposed recovery method of the remaining net

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1 book balances of these plants which ensures that the Company will not be financially
2 harmed by the accelerated retirements.

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

16 As explained in the direct testimony of Company witness Maddipati, the Company
17 is proposing to recover the remaining net book balances consistent with the design lives of
18 the units, as opposed to the proposed retirement dates, because it is consistent with the
19 recovery currently in customer rates and balances the rate impacts of current customers
20 with the impacts to future customers. The Company's proposed regulatory asset treatment
21 is also a necessary element of the Company's PCA due to Generally Accepted Accounting
22 Principles. Company witness Coker explains that, under Generally Accepted Accounting
23 Principles, the net book balances of the plants must be removed from plant-in-service when

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1 it becomes probable that a plant will be abandoned before the end of its useful life. If the
2 Commission approves the PCA in this case it would become probable, under accounting
3 standards, that the plants will be retired and abandoned. If the Commission authorizes
4 regulatory asset treatment with full return, a regulatory asset in the amount of the remaining
5 net book balances would be recorded and no impairment loss would be recorded. However,
6 if the Commission does not authorize a method of recovering the remaining net book
7 balances of the plants including full recovery of financing costs, at the same time the PCA
8 is approved, the Company would be required to write off a portion of the net book balances
9 of Karn Units 3 and 4 and Campbell Units 1, 2, and 3 and record an impairment for
10 accounting purposes.

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

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

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

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

- 7 1) The accelerated retirement of the Company's Karn Units 3 and 4 by May 31,
8 2023, and the Company's Campbell Units 1, 2, and 3 by May 31, 2025, and the
9 replacement of those resources with the purchase of existing gas resources, in
10 addition to the expansion of the levels of solar and demand-side resources. The
11 purchase of existing gas units will include the purchase of the Covert Plant by
12 May 31, 2023, and the purchase of the DIG, Livingston, and Kalamazoo plants
13 by May 31, 2025. The accelerated retirement and purchase of the
14 aforementioned resources are conditioned on: (i) the approval of the Company's
15 proposed regulatory asset treatment to recover the remaining net book balances
16 of the above identified Campbell and Karn units through their current design
17 lives, and (ii) approval of the acquisition and purchase costs of the Covert, DIG,
18 Livingston, and Kalamazoo plants (\$1.345 billion), in the manner described in
19 the Company's direct testimony and exhibits, are reasonable and prudent for
20 cost recovery purposes pursuant to MCL 460.6t;
- 21 2) Certain accounting approvals which include: (i) regulatory asset treatment, with
22 full return, to recover the remaining net book balances of Karn Units 3 and 4
23 and Campbell Units 1, 2, and 3 through their current design lives; (ii) approval
24 to defer employee retention costs; and (iii) approval to make retirement
25 transition costs a regulatory asset;
- 26 3) Approval of the selection and proposed purchase of the DIG, Kalamazoo, and
27 Livingston plants by Consumers Energy from its affiliate, CMS Enterprises.
28 The transaction was a result of a competitive solicitation and is compliant with
29 the Commission's Code of Conduct requirements. The competitive solicitation
30 also complied with FERC's standards for determining that an acquisition
31 involving an affiliate will not adversely affect competition and is consistent
32 with the public interest as it satisfied the four principles – Transparency,
33 Definition, Evaluation, and Oversight – of FERC's solicitation guidelines. In
34 the alternative, while complying with all other provisions of the Code of
35 Conduct, the Company requests a waiver of the asset transfer provision of the
36 Code of Conduct, Mich Admin Code R 460.10108(4), for the acquisition of the
37 DIG, Kalamazoo, and Livingston plants from CMS Enterprises;

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- 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.

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1 **Q. Please summarize your direct testimony.**

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

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

11 **Q. Does this complete your direct testimony?**

12 A. Yes, it does.

Attachment EE

JH Campbell ROP

**MICHIGAN DEPARTMENT OF ENVIRONMENT, GREAT LAKES, AND ENERGY
AIR QUALITY DIVISION**

EFFECTIVE DATE: February 4, 2020
REVISION DATES: September 3, 2020, July 2, 2021

ISSUED TO

Consumers Energy, J.H. Campbell Generating Complex

State Registration Number (SRN): B2835

LOCATED AT

17000 Croswell, West Olive, Ottawa County, Michigan 49460

RENEWABLE OPERATING PERMIT

Permit Number: MI-ROP-B2835-2020b

Expiration Date: February 4, 2025

Administratively Complete ROP Renewal Application
Due Between August 4, 2023 and August 4, 2024

This Renewable Operating Permit (ROP) is issued in accordance with and subject to Section 5506(3) of Part 55, Air Pollution Control, of the Natural Resources and Environmental Protection Act, 1994 PA 451, as amended (Act 451). Pursuant to Rule 210(1) of the administrative rules promulgated under Act 451, this ROP constitutes the permittee's authority to operate the stationary source identified above in accordance with the general conditions, special conditions and attachments contained herein. Operation of the stationary source and all emission units listed in the permit are subject to all applicable future or amended rules and regulations pursuant to Act 451 and the federal Clean Air Act.

SOURCE-WIDE PERMIT TO INSTALL

Permit Number: MI-PTI-B2835-2020b

This Permit to Install (PTI) is issued in accordance with and subject to Section 5505(1) of Act 451. Pursuant to Rule 214a of the administrative rules promulgated under Act 451, the terms and conditions herein, identified by the underlying applicable requirement citation of Rule 201(1)(a), constitute a federally enforceable PTI. The PTI terms and conditions do not expire and remain in effect unless the criteria of Rule 201(6) are met. Operation of all emission units identified in the PTI is subject to all applicable future or amended rules and regulations pursuant to Act 451 and the federal Clean Air Act.

Michigan Department of Environment, Great Lakes, and Energy

Heidi Hollenbach, Grand Rapids District Supervisor

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AUTHORITY AND ENFORCEABILITY

For the purpose of this permit, the **permittee** is defined as any person who owns or operates an emission unit at a stationary source for which this permit has been issued. The **department** is defined in Rule 104(d) as the Director of the Michigan Department of Environment, Great Lakes, and Energy (EGLE) or his or her designee.

The permittee shall comply with all specific details in the permit terms and conditions and the cited underlying applicable requirements. All terms and conditions in this ROP are both federally enforceable and state enforceable unless otherwise footnoted. Certain terms and conditions are applicable to most stationary sources for which an ROP has been issued. These general conditions are included in Part A of this ROP. Other terms and conditions may apply to a specific emission unit, several emission units which are represented as a flexible group, or the entire stationary source which is represented as a Source-Wide group. Special conditions are identified in Parts B, C, D and/or the appendices.

In accordance with Rule 213(2)(a), all underlying applicable requirements are identified for each ROP term or condition. All terms and conditions that are included in a PTI are streamlined, subsumed and/or is state-only enforceable will be noted as such.

In accordance with Section 5507 of Act 451, the permittee has included in the ROP application a compliance certification, a schedule of compliance, and a compliance plan. For applicable requirements with which the source is in compliance, the source will continue to comply with these requirements. For applicable requirements with which the source is not in compliance, the source will comply with the detailed schedule of compliance requirements that are incorporated as an appendix in this ROP. Furthermore, for any applicable requirements effective after the date of issuance of this ROP, the stationary source will meet the requirements on a timely basis, unless the underlying applicable requirement requires a more detailed schedule of compliance.

Issuance of this permit does not obviate the necessity of obtaining such permits or approvals from other units of government as required by law.

This permit does not relieve the permittee from any responsibilities or obligations imposed on the permittee, at the source under Consent Decree U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014, entered in 2014 between the USEPA and the permittee.

A. GENERAL CONDITIONS

Permit Enforceability

- All conditions in this permit are both federally enforceable and state enforceable unless otherwise noted. **(R 336.1213(5))**
- Those conditions that are hereby incorporated in a state-only enforceable Source-Wide PTI pursuant to Rule 201(2)(d) are designated by footnote one. **(R 336.1213(5)(a), R 336.1214a(5))**
- Those conditions that are hereby incorporated in a federally enforceable Source-Wide PTI pursuant to Rule 201(2)(c) are designated by footnote two. **(R 336.1213(5)(b), R 336.1214a(3))**

General Provisions

1. The permittee shall comply with all conditions of this ROP. Any ROP noncompliance constitutes a violation of Act 451, and is grounds for enforcement action, for ROP revocation or revision, or for denial of the renewal of the ROP. All terms and conditions of this ROP that are designated as federally enforceable are enforceable by the Administrator of the United States Environmental Protection Agency (USEPA) and by citizens under the provisions of the federal Clean Air Act (CAA). Any terms and conditions based on applicable requirements which are designated as "state-only" are not enforceable by the USEPA or citizens pursuant to the CAA. **(R 336.1213(1)(a))**
2. It shall not be a defense for the permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this ROP. **(R 336.1213(1)(b))**
3. This ROP may be modified, revised, or revoked for cause. The filing of a request by the permittee for a permit modification, revision, or termination, or a notification of planned changes or anticipated noncompliance does not stay any ROP term or condition. This does not supersede or affect the ability of the permittee to make changes, at the permittee's own risk, pursuant to Rule 215 and Rule 216. **(R 336.1213(1)(c))**
4. The permittee shall allow the department, or an authorized representative of the department, upon presentation of credentials and other documents as may be required by law and upon stating the authority for and purpose of the investigation, to perform any of the following activities: **(R 336.1213(1)(d))**
 - a. Enter, at reasonable times, a stationary source or other premises where emissions-related activity is conducted or where records must be kept under the conditions of the ROP.
 - b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of the ROP.
 - c. Inspect, at reasonable times, any of the following:
 - i. Any stationary source.
 - ii. Any emission unit.
 - iii. Any equipment, including monitoring and air pollution control equipment.
 - iv. Any work practices or operations regulated or required under the ROP.
 - d. As authorized by Section 5526 of Act 451, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the ROP or applicable requirements.
5. The permittee shall furnish to the department, within a reasonable time, any information the department may request, in writing, to determine whether cause exists for modifying, revising, or revoking the ROP or to determine compliance with this ROP. Upon request, the permittee shall also furnish to the department copies of any records that are required to be kept as a term or condition of this ROP. For information which is claimed by the permittee to be confidential, consistent with the requirements of the 1976 PA 442, MCL §15.231 et seq., and known as the Freedom of Information Act, the person may also be required to furnish the records directly to the USEPA together with a claim of confidentiality. **(R 336.1213(1)(e))**

6. A challenge by any person, the Administrator of the USEPA, or the department to a particular condition or a part of this ROP shall not set aside, delay, stay, or in any way affect the applicability or enforceability of any other condition or part of this ROP. **(R 336.1213(1)(f))**
7. The permittee shall pay fees consistent with the fee schedule and requirements pursuant to Section 5522 of Act 451. **(R 336.1213(1)(g))**
8. This ROP does not convey any property rights or any exclusive privilege. **(R 336.1213(1)(h))**

Equipment & Design

9. Any collected air contaminants shall be removed as necessary to maintain the equipment at the required operating efficiency. The collection and disposal of air contaminants shall be performed in a manner so as to minimize the introduction of contaminants to the outer air. Transport of collected air contaminants in Priority I and II areas requires the use of material handling methods specified in Rule 370(2).² **(R 336.1370)**
10. Any air cleaning device shall be installed, maintained, and operated in a satisfactory manner and in accordance with the Michigan Air Pollution Control rules and existing law. **(R 336.1910)**

Emission Limits

11. Unless otherwise specified in this ROP, the permittee shall comply with Rule 301, which states, in part, "Except as provided in Subrules 2, 3, and 4 of this rule, a person shall not cause or permit to be discharged into the outer air from a process or process equipment a visible emission of a density greater than the most stringent of the following:"² **(R 336.1301(1))**
 - a. A 6-minute average of 20% opacity, except for one 6-minute average per hour of not more than 27% opacity.
 - b. A limit specified by an applicable federal new source performance standard.

The grading of visible emissions shall be determined in accordance with Rule 303.

12. The permittee shall not cause or permit the emission of an air contaminant or water vapor in quantities that cause, alone or in reaction with other air contaminants, either of the following:
 - a. Injurious effects to human health or safety, animal life, plant life of significant economic value, or property.¹ **(R 336.1901(a))**
 - b. Unreasonable interference with the comfortable enjoyment of life and property.¹ **(R 336.1901(b))**

Testing/Sampling

13. The department may require the owner or operator of any source of an air contaminant to conduct acceptable performance tests, at the owner's or operator's expense, in accordance with Rule 1001 and Rule 1003, under any of the conditions listed in Rule 1001(1).² **(R 336.2001)**
14. Any required performance testing shall be conducted in accordance with Rule 1001(2), Rule 1001(3) and Rule 1003. **(R 336.2001(2), R 336.2001(3), R 336.2003(1))**
15. Any required test results shall be submitted to the Air Quality Division (AQD) in the format prescribed by the applicable reference test method within 60 days following the last date of the test. **(R 336.2001(5))**

Monitoring/Recordkeeping

16. Records of any periodic emission or parametric monitoring required in this ROP shall include the following information specified in Rule 213(3)(b)(i), where appropriate. **(R 336.1213(3)(b))**
 - a. The date, location, time, and method of sampling or measurements.
 - b. The dates the analyses of the samples were performed.
 - c. The company or entity that performed the analyses of the samples.
 - d. The analytical techniques or methods used.
 - e. The results of the analyses.
 - f. The related process operating conditions or parameters that existed at the time of sampling or measurement.
17. All required monitoring data, support information and all reports, including reports of all instances of deviation from permit requirements, shall be kept and furnished to the department upon request for a period of not less than 5 years from the date of the monitoring sample, measurement, report or application. Support information includes all calibration and maintenance records and all original strip-chart recordings, or other original data records, for continuous monitoring instrumentation and copies of all reports required by the ROP. **(R 336.1213(1)(e), R 336.1213(3)(b)(ii))**

Certification & Reporting

18. Except for the alternate certification schedule provided in Rule 213(3)(c)(iii)(B), any document required to be submitted to the department as a term or condition of this ROP shall contain an original certification by a Responsible Official which state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. **(R 336.1213(3)(c))**
19. A Responsible Official shall certify to the appropriate AQD District Office and to the USEPA that the stationary source is and has been in compliance with all terms and conditions contained in the ROP except for deviations that have been or are being reported to the appropriate AQD District Office pursuant to Rule 213(3)(c). This certification shall include all the information specified in Rule 213(4)(c)(i) through (v) and shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the certification are true, accurate, and complete. The USEPA address is: USEPA, Air Compliance Data - Michigan, Air and Radiation Division, 77 West Jackson Boulevard, Chicago, Illinois 60604-3507. **(R 336.1213(4)(c))**
20. The certification of compliance shall be submitted annually for the term of this ROP as detailed in the special conditions, or more frequently if specified in an applicable requirement or in this ROP. **(R 336.1213(4)(c))**
21. The permittee shall promptly report any deviations from ROP requirements and certify the reports. The prompt reporting of deviations from ROP requirements is defined in Rule 213(3)(c)(ii) as follows, unless otherwise described in this ROP. **(R 336.1213(3)(c))**
 - a. For deviations that exceed the emissions allowed under the ROP, prompt reporting means reporting consistent with the requirements of Rule 912 as detailed in Condition 25. All reports submitted pursuant to this paragraph shall be promptly certified as specified in Rule 213(3)(c)(iii).
 - b. For deviations which exceed the emissions allowed under the ROP and which are not reported pursuant to Rule 912 due to the duration of the deviation, prompt reporting means the reporting of all deviations in the semiannual reports required by Rule 213(3)(c)(i). The report shall describe reasons for each deviation and the actions taken to minimize or correct each deviation.
 - c. For deviations that do not exceed the emissions allowed under the ROP, prompt reporting means the reporting of all deviations in the semiannual reports required by Rule 213(3)(c)(i). The report shall describe the reasons for each deviation and the actions taken to minimize or correct each deviation.

22. For reports required pursuant to Rule 213(3)(c)(ii), prompt certification of the reports is described in Rule 213(3)(c)(iii) as either of the following: **(R 336.1213(3)(c))**
- Submitting a certification by a Responsible Official with each report which states that, based on information and belief formed after reasonable inquiry, the statements and information in the report are true, accurate, and complete.
 - Submitting, within 30 days following the end of a calendar month during which one or more prompt reports of deviations from the emissions allowed under the ROP were submitted to the department pursuant to Rule 213(3)(c)(ii), a certification by a Responsible Official which states that; "based on information and belief formed after reasonable inquiry, the statements and information contained in each of the reports submitted during the previous month were true, accurate, and complete." The certification shall include a listing of the reports that are being certified. Any report submitted pursuant to Rule 213(3)(c)(ii) that will be certified on a monthly basis pursuant to this paragraph shall include a statement that certification of the report will be provided within 30 days following the end of the calendar month.
23. Semiannually for the term of the ROP as detailed in the special conditions, or more frequently if specified, the permittee shall submit certified reports of any required monitoring to the appropriate AQD District Office. All instances of deviations from ROP requirements during the reporting period shall be clearly identified in the reports. **(R 336.1213(3)(c)(i))**
24. On an annual basis, the permittee shall report the actual emissions, or the information necessary to determine the actual emissions, of each regulated air pollutant as defined in Rule 212(6) for each emission unit utilizing the emissions inventory forms provided by the department. **(R 336.1212(6))**
25. The permittee shall provide notice of an abnormal condition, start-up, shutdown, or malfunction that results in emissions of a hazardous or toxic air pollutant which continue for more than one hour in excess of any applicable standard or limitation, or emissions of any air contaminant continuing for more than two hours in excess of an applicable standard or limitation, as required in Rule 912, to the appropriate AQD District Office. The notice shall be provided not later than two business days after the start-up, shutdown, or discovery of the abnormal conditions or malfunction. Notice shall be by any reasonable means, including electronic, telephonic, or oral communication. Written reports, if required under Rule 912, must be submitted to the appropriate AQD District Supervisor within 10 days after the start-up or shutdown occurred, within 10 days after the abnormal conditions or malfunction has been corrected, or within 30 days of discovery of the abnormal conditions or malfunction, whichever is first. The written reports shall include all of the information required in Rule 912(5) and shall be certified by a Responsible Official in a manner consistent with the CAA.² **(R 336.1912)**

Permit Shield

26. Compliance with the conditions of the ROP shall be considered compliance with any applicable requirements as of the date of ROP issuance if either of the following provisions is satisfied. **(R 336.1213(6)(a)(i), R 336.1213(6)(a)(ii))**
- The applicable requirements are included and are specifically identified in the ROP.
 - The permit includes a determination or concise summary of the determination by the department that other specifically identified requirements are not applicable to the stationary source.

Any requirements identified in Part E of this ROP have been identified as non-applicable to this ROP and are included in the permit shield.

27. Nothing in this ROP shall alter or affect any of the following:
- The provisions of Section 303 of the CAA, emergency orders, including the authority of the USEPA under Section 303 of the CAA. **(R 336.1213(6)(b)(i))**
 - The liability of the owner or operator of this source for any violation of applicable requirements prior to or at the time of this ROP issuance. **(R 336.1213(6)(b)(ii))**
 - The applicable requirements of the acid rain program, consistent with Section 408(a) of the CAA. **(R 336.1213(6)(b)(iii))**

- d. The ability of the USEPA to obtain information from a source pursuant to Section 114 of the CAA. **(R 336.1213(6)(b)(iv))**
- 28. The permit shield shall not apply to provisions incorporated into this ROP through procedures for any of the following:
 - a. Operational flexibility changes made pursuant to Rule 215. **(R 336.1215(5))**
 - b. Administrative Amendments made pursuant to Rule 216(1)(a)(i)-(iv). **(R 336.1216(1)(b)(iii))**
 - c. Administrative Amendments made pursuant to Rule 216(1)(a)(v) until the amendment has been approved by the department. **(R 336.1216(1)(c)(iii))**
 - d. Minor Permit Modifications made pursuant to Rule 216(2). **(R 336.1216(2)(f))**
 - e. State-Only Modifications made pursuant to Rule 216(4) until the changes have been approved by the department. **(R 336.1216(4)(e))**
- 29. Expiration of this ROP results in the loss of the permit shield. If a timely and administratively complete application for renewal is submitted not more than 18 months, but not less than 6 months, before the expiration date of the ROP, but the department fails to take final action before the end of the ROP term, the existing ROP does not expire until the renewal is issued or denied, and the permit shield shall extend beyond the original ROP term until the department takes final action. **(R 336.1217(1)(c), R 336.1217(1)(a))**

Revisions

- 30. For changes to any process or process equipment covered by this ROP that do not require a revision of the ROP pursuant to Rule 216, the permittee must comply with Rule 215. **(R 336.1215, R 336.1216)**
- 31. A change in ownership or operational control of a stationary source covered by this ROP shall be made pursuant to Rule 216(1). **(R 336.1219(2))**
- 32. For revisions to this ROP, an administratively complete application shall be considered timely if it is received by the department in accordance with the time frames specified in Rule 216. **(R 336.1210(10))**
- 33. Pursuant to Rule 216(1)(b)(iii), Rule 216(2)(d) and Rule 216(4)(d), after a change has been made, and until the department takes final action, the permittee shall comply with both the applicable requirements governing the change and the ROP terms and conditions proposed in the application for the modification. During this time period, the permittee may choose to not comply with the existing ROP terms and conditions that the application seeks to change. However, if the permittee fails to comply with the ROP terms and conditions proposed in the application during this time period, the terms and conditions in the ROP are enforceable. **(R 336.1216(1)(c)(iii), R 336.1216(2)(d), R 336.1216(4)(d))**

Reopenings

- 34. A ROP shall be reopened by the department prior to the expiration date and revised by the department under any of the following circumstances:
 - a. If additional requirements become applicable to this stationary source with three or more years remaining in the term of the ROP, but not if the effective date of the new applicable requirement is later than the ROP expiration date. **(R 336.1217(2)(a)(i))**
 - b. If additional requirements pursuant to Title IV of the CAA become applicable to this stationary source. **(R 336.1217(2)(a)(ii))**
 - c. If the department determines that the ROP contains a material mistake, information required by any applicable requirement was omitted, or inaccurate statements were made in establishing emission limits or the terms or conditions of the ROP. **(R 336.1217(2)(a)(iii))**
 - d. If the department determines that the ROP must be revised to ensure compliance with the applicable requirements. **(R 336.1217(2)(a)(iv))**

Renewals

35. For renewal of this ROP, an administratively complete application shall be considered timely if it is received by the department not more than 18 months, but not less than 6 months, before the expiration date of the ROP. **(R 336.1210(9))**

Stratospheric Ozone Protection

36. If the permittee is subject to Title 40 of the Code of Federal Regulations (CFR), Part 82 and services, maintains, or repairs appliances except for motor vehicle air conditioners (MVAC), or disposes of appliances containing refrigerant, including MVAC and small appliances, or if the permittee is a refrigerant reclaiming, appliance owner or a manufacturer of appliances or recycling and recovery equipment, the permittee shall comply with all applicable standards for recycling and emissions reduction pursuant to 40 CFR Part 82, Subpart F.
37. If the permittee is subject to 40 CFR Part 82 and performs a service on motor (fleet) vehicles when this service involves refrigerant in the MVAC, the permittee is subject to all the applicable requirements as specified in 40 CFR Part 82, Subpart B, Servicing of Motor Vehicle Air Conditioners. The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed by the original equipment manufacturer. The term MVAC as used in Subpart B does not include the air-tight sealed refrigeration system used for refrigerated cargo or an air conditioning system on passenger buses using Hydrochlorofluorocarbon-22 refrigerant.

Risk Management Plan

38. If subject to Section 112(r) of the CAA and 40 CFR Part 68, the permittee shall register and submit to the USEPA the required data related to the risk management plan for reducing the probability of accidental releases of any regulated substances listed pursuant to Section 112(r)(3) of the CAA as amended in 40 CFR 68.130. The list of substances, threshold quantities, and accident prevention regulations promulgated under 40 CFR Part 68, do not limit in any way the general duty provisions under Section 112(r)(1).
39. If subject to Section 112(r) of the CAA and 40 CFR Part 68, the permittee shall comply with the requirements of 40 CFR Part 68, no later than the latest of the following dates as provided in 40 CFR 68.10(a):
- June 21, 1999,
 - Three years after the date on which a regulated substance is first listed under 40 CFR 68.130, or
 - The date on which a regulated substance is first present above a threshold quantity in a process.
40. If subject to Section 112(r) of the CAA and 40 CFR Part 68, the permittee shall submit any additional relevant information requested by any regulatory agency necessary to ensure compliance with the requirements of 40 CFR Part 68.
41. If subject to Section 112(r) of the CAA and 40 CFR Part 68, the permittee shall annually certify compliance with all applicable requirements of Section 112(r) as detailed in Rule 213(4)(c)). **(40 CFR Part 68)**

Emission Trading

42. Emission averaging and emission reduction credit trading are allowed pursuant to any applicable interstate or regional emission trading program that has been approved by the Administrator of the USEPA as a part of Michigan's State Implementation Plan. Such activities must comply with Rule 215 and Rule 216. **(R 336.1213(12))**

Permit to Install (PTI)

43. The process or process equipment included in this permit shall not be reconstructed, relocated, or modified unless a PTI authorizing such action is issued by the department, except to the extent such action is exempt from the PTI requirements by any applicable rule.² **(R 336.1201(1))**
44. The department may, after notice and opportunity for a hearing, revoke PTI terms or conditions if evidence indicates the process or process equipment is not performing in accordance with the terms and conditions of the PTI or is violating the department's rules or the CAA.² **(R 336.1201(8), Section 5510 of Act 451)**
45. The terms and conditions of a PTI shall apply to any person or legal entity that now or hereafter owns or operates the process or process equipment at the location authorized by the PTI. If a new owner or operator submits a written request to the department pursuant to Rule 219 and the department approves the request, this PTI will be amended to reflect the change of ownership or operational control. The request must include all of the information required by Subrules (1)(a), (b) and (c) of Rule 219. The written request shall be sent to the appropriate AQD District Supervisor, EGLE.² **(R 336.1219)**
46. If the installation, reconstruction, relocation, or modification of the equipment for which PTI terms and conditions have been approved has not commenced within 18 months of the original PTI issuance date, or has been interrupted for 18 months, the applicable terms and conditions from that PTI, as incorporated into the ROP, shall become void unless otherwise authorized by the department. Furthermore, the person to whom that PTI was issued, or the designated authorized agent, shall notify the department via the Supervisor, Permit Section, EGLE, AQD, P. O. Box 30260, Lansing, Michigan 48909, if it is decided not to pursue the installation, reconstruction, relocation, or modification of the equipment allowed by the terms and conditions from that PTI.² **(R 336.1201(4))**

Footnotes:

¹This condition is state-only enforceable and was established pursuant to Rule 201(1)(b).

²This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

B. SOURCE-WIDE CONDITIONS

Part B outlines the Source-Wide Terms and Conditions that apply to this stationary source. The permittee is subject to these special conditions for the stationary source in addition to the general conditions in Part A and any other terms and conditions contained in this ROP.

The permittee shall comply with all specific details in the special conditions and the underlying applicable requirements cited. If a specific condition type does not apply to this source, NA (not applicable) has been used in the table. If there are no Source-Wide Conditions, this section will be left blank.

C. EMISSION UNIT SPECIAL CONDITIONS

Part C outlines terms and conditions that are specific to individual emission units listed in the Emission Unit Summary Table. The permittee is subject to the special conditions for each emission unit in addition to the General Conditions in Part A and any other terms and conditions contained in this ROP.

The permittee shall comply with all specific details in the special conditions and the underlying applicable requirements cited. If a specific condition type does not apply, NA (not applicable) has been used in the table. If there are no conditions specific to individual emission units, this section will be left blank.

EMISSION UNIT SUMMARY TABLE

The descriptions provided below are for informational purposes and do not constitute enforceable conditions.

Emission Unit ID	Emission Unit Description (Including Process Equipment & Control Device(s))	Installation Date/ Modification Date	Flexible Group ID
EUPARTSCLEANERS	Multiple individual cleaning units that are subject to the same applicable requirements. The cleaning units are used in support of facility operations.	01-01-1994/ NA	FGPARTSCLEANERS
EUBOILER1	A 2490 MMBTU per hour dry bottom, tangential fired boiler with fuel oil startup capabilities. Emissions are currently controlled by low-NOx burners, sorbent injection (ACI) (activated carbon or other sorbent for mercury control), dry sorbent injection (DSI) (hydrated lime or other sorbent), and a pulse-jet fabric filter (PJFF) baghouse.	01-01-1958/ 04-23-2015	FGMATS_U12 FGBOILER12
EUBOILER2	A 3560 MMBTU per hour wall-fired (converted from cell burner) boiler with fuel oil startup capability. Emissions are controlled by low-NOx burners, selective catalytic reduction (SCR), sorbent injection (ACI) (activated carbon or other sorbent for mercury control), DSI (hydrated lime or other sorbent), and a PJFF baghouse.	01-01-1963/ 04-23-2015	FGMATS_U12 FGBOILER12
EUBOILER3	An 8240 MMBTU per hour dry bottom, wall-fired boiler with fuel oil startup capability. Emissions are controlled by low-NOx burners, SCR, sorbent injection (ACI) (activated carbon or other sorbent for mercury control), spray dry absorber (SDA), and PJFF baghouse.	02-01-1974/ 04-23-2015	FGMATS_U3
EUCOALHAND	Coal handling facility. Particulate emissions are controlled by 11 baghouses, enclosures, and dust suppression.	01-01-1958	NA

Emission Unit ID	Emission Unit Description (Including Process Equipment & Control Device(s))	Installation Date/ Modification Date	Flexible Group ID
EUSDA_U3	Lime preparation operations for Boiler 3 that support the SDA including storage silos, vertical ball mills, lime slurry transfer and product tanks. Emissions are controlled by bin vent filters and spray scrubbers (mill scrubbers). SDA operations for Boiler 3 includes lime slurry atomizer head tanks, recycle silos, recycle mix tanks, and recycle slurry storage tanks. Emissions are controlled by bin vent filters and a spray scrubber (recycle mix tank).	04-23-2015	NA
EUDSI_U12	Dry Sorbent Injection Material Handling for Boilers 1 and 2. Includes sorbent silos (hydrated lime or other sorbent) and pneumatic transfer; bin vent filters.	04-23-2015	NA
EUACI_U123	Activated carbon (or other sorbent) material handling including silos for Boiler Units 1, 2 and 3; with bin vent filters.	04-23-2015	NA
EUBYPRODUCT	There are three separate byproduct handling systems (one for each boiler). The system transfers the byproduct from the fabric filters (ash, spent lime, and sorbent) to the disposal silos. The equipment includes conveyance piping and byproduct transfer tanks, filter separator, vacuum exhausters, and conveying blowers from transfer tanks to flyash storage/disposal silos. Dry flyash handling facility is located at the landfill and is common to Boilers 1, 2, and 3 and consists of three flyash storage/disposal silos; with flyash truck dry load outs. Emissions control: The transfer tanks' byproduct vacuum exhauster filter separators exhaust to the boiler pulse-jet fabric filters (except as noted in the emission unit requirements); bin vent filters on the byproduct transfer tanks and flyash silos. Water added for flyash conditioning before flyash truck loading for disposal.	04-23-2015	NA
EUAUXBLR12	A 17 MMBTU/hr fuel oil-fired firetube auxiliary boiler servicing EUBOILER1 and EUBOILER2. This boiler is a limited use boiler.	01-01-1958	NA
EUAUXBLR3B	A 9.8 MMBTU/hr fuel oil fired auxiliary boiler providing heat to Plant 3.	11-2011	FGAUXBLRS3
EUAUXBLR3C	A 9.8 MMBTU/hr fuel oil fired auxiliary boiler providing heat to Plant 3.	11-2011	FGAUXBLRS3
EUCAT3DIESEL	A diesel-powered, stationary internal combustion engine rated at 9.3 MMBTU/hr heat input.	02-01-1974	NA

Emission Unit ID	Emission Unit Description (Including Process Equipment & Control Device(s))	Installation Date/ Modification Date	Flexible Group ID
EUWPDIESEL	Water Pump for EUSDA_U3 emergency flush certified to NSPS III Tier 3 requirements. A diesel-powered, stationary internal combustion engine rated at 130 HP (97 kW).	07-2016	FGNEWCIRICE
EUCATFIREPUMP3	A diesel-powered, stationary internal combustion Caterpillar 3406 model engine rated at 2.8 MMBTU/hr heat input; used as a fire pump.	01-2017	FGEXISTINGRICE
EUHPHSWP15001	A diesel-powered, stationary internal combustion engine rated at 3.05 MMBTU/hr heat input; Emergency Diesel Generator #1.	01-01-1958	FGEXISTINGRICE
EUHPHSWP15002	A diesel-powered, stationary internal combustion engine rated at 3.05 MMBTU/hr heat input; Emergency Diesel Generator #2.	01-01-1958	FGEXISTINGRICE
EUHPHSWP3000	A diesel-powered, stationary internal combustion engine rated at 2.58 MMBTU/hr heat input; Emergency Diesel Generator.	01-01-1958	FGEXISTINGRICE
EUCATDIESEL12	A 2,000-kilowatt (kW) diesel-fueled emergency engine manufactured in 2007 or later.	10-12-2012	NA
EUTRNCNTRDIESEL	A diesel-powered, stationary internal combustion engine rated at 1193 BHP; Emergency Diesel Generator.	08-2013	FGNEWCIRICE
EUGUARDSHK_ENG	A natural-gas, stationary internal combustion engine rated at 40 HP; Emergency Generator for the guard shack.	08-2015	NA

EUBOILER1 EMISSION UNIT CONDITIONS

DESCRIPTION

A 2490 MMBTU/hr dry bottom, tangential fired boiler with fuel oil startup capability. This emission unit is subject to 40 CFR Part 63, Subpart UUUUU (MATS) and 40 CFR Part 64 (CAM). All CAM requirements are in FGBOILER12 and all MATS requirements are in FGMATS_U12.

Flexible Group ID: FGBOILER12 and FGMATS_U12

POLLUTION CONTROL EQUIPMENT

Low-NOx burners,
Sorbent injection (ACI) (activated carbon or other sorbent for mercury control),
Dry sorbent injection (DSI) (hydrated lime or other sorbent), and
Pulse-jet fabric filter (PJFF) baghouse.

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Particulate matter (PM)	0.16 pound per 1,000 pounds exhaust gas, corrected to 50% excess air ²	Hourly	EUBOILER1	SC V.1 (FGBOILER12, SC VI.1, COMS)	R 336.1331(1)(c)
2. NO _x	0.220 pound per MMBTU heat input ^{2,3,4}	Based on a 365-day Rolling Average Emission Rate ^{2,3,4}	EUBOILER1	SC VI.1	“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” paragraph 76; Act 451, Section 324.5503(b)
3. SO ₂	0.350 pounds per MMBTU heat input ^{2,3,4}	Based on a 30-day Rolling Average Emission Rate ^{2,3,4}	EUBOILER1	SC VI.1 SC VI.2	“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” paragraph 113; Act 451, Section 324.5503(b)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
4. SO ₂	0.290 pound per MMBTU heat input ^{2,3,4}	Based on a 90-day Rolling Average Emission Rate ^{2,3,4}	EUBOILER1	SC VI.1 SC VI.2	“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” paragraph 113; Act 451, Section 324.5503(b)
5. PM	0.015 pound per MMBTU heat input ^{2,3,4}	Hourly ^{2,3,4}	EUBOILER1	SC V.2 (FGBOILER12, SC VI.1, COMS)	“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” paragraph 144; Act 451, Section 324.5503(b)
6. Opacity	20% ^{2,3,4}	Per 6-minute period except for one 6-minute period per hour of not more than 27% ^{2,3,4}	EUBOILER1	SC VI.4	“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” paragraph 151; Act 451, Section 324.5503(b)
7. SO ₂	1.67 pounds per MMBTU heat input ²	Monthly average, based on the average of the 31 previous operating days	EUBOILER1	SC VI.3	R 336.1401(3), Table 41

8. The permittee shall comply with the System-Wide Annual NO_x Tonnage Limitations and System-Wide Annual SO₂ Tonnage Limitations specified in Appendix 11-A. Emissions from EUBOILER1 shall be counted toward the system-wide total emissions.^{2,3,4} (**“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” paragraphs 98 & 129, Act 451, Section 324.5503(b)**)
9. The permittee shall comply with the SO₂ and NO_x allowance surrender and super-compliance allowance provisions listed in Appendix 11-B: Allowance Provisions.^{2,3,4} (**“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” paragraphs 101-109 and 132-140, Act 451, Section 324.5503(b)**)

See Appendices 11-A and 11-B

II. MATERIAL LIMIT(S)

Material	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Coal – sulfur content	1.0% by weight, at a heat content of 12,000 BTU/lb ²	Monthly average, based on the average of the 31 previous operating days	EUBOILER1	SC VI.3	R 336.1401(3), Table 41

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall not operate EUBOILER1 unless a malfunction abatement plan (MAP) as described in Rule 911(2), for the emission control equipment (PJFF baghouse, ACI, DSI) is implemented and maintained. The MAP shall, at a minimum, specify the following:
 - a. A complete preventative maintenance program including identification of the supervisory personnel responsible for overseeing the inspection, maintenance, and repair of air-cleaning devices, a description of the items or conditions that shall be inspected, the frequency of the inspections or repairs, and an identification of the major replacement parts that shall be maintained in inventory for quick replacement.
 - b. An identification of the source and air-cleaning device operating variables that shall be monitored to detect a malfunction or failure, the normal operating range of these variables, and a description of the method of monitoring or surveillance procedures.
 - c. A description of the corrective procedures or operational changes that shall be taken in the event of a malfunction or failure to achieve compliance with the applicable emission limits.

If at any time the MAP fails to address or inadequately addresses an event that meets the characteristics of a malfunction, the permittee shall amend the MAP within 45 days after such an event occurs. The permittee shall also amend the MAP within 45 days, if new equipment is installed or upon request from the District Supervisor. The permittee shall submit the MAP and any amendments to the MAP to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the MAP or amended MAP shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.² **(R 336.1910, R 336.1911)**

2. The permittee shall continuously operate the PM Control Device for EUBOILER1 and use good air pollution control practices to maximize the PM emission reductions at all times when the unit is in operation. The requirements of Appendix 3-F shall be met.^{2,3,4} **(“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” – paragraph 141, Act 451, Section 324.5503(b))**
3. The permittee shall not operate the boiler, including startup and shutdown, unless the corresponding PJFF baghouse is installed and operating properly, in accordance with safe operating practices.² **(R 336.1910)**
4. The permittee shall not burn freeze conditioning/dust suppression agents unless PJFF baghouses are installed and operating properly, in accordance with safe operating practices.² **(R 336.1910)**

See Appendix 3-F

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall not operate EUBOILER1 unless the low-NOx burners, the DSI, the ACI sorbent injection (for mercury control), and PJFF baghouse are installed, maintained, and operated in a satisfactory manner. Satisfactory manner includes operating and maintaining each control device in accordance with an approvable MAP for EUBOILER1 control equipment as required in SC III.1.² **(R 336.1910)**

2. The permittee shall not operate EUBOILER1 unless the low-NO_x burners, including over fire air processes, are Continuously Operated.^{2,3,4} (“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” – paragraph 75, Act 451, Section 324.5503(b))
3. The permittee shall not operate EUBOILER1 unless the DSI system is Continuously Operated.^{2,3,4} (“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” – paragraph 113, Act 451, Section 324.5503(b))
4. The permittee shall not operate EUBOILER1 unless the PJFF baghouse unit is Continuously Operated.^{2,3,4} (“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” – paragraph 144, Act 451, Section 324.5503(b))
5. The permittee shall continuously operate the PM control devices being vented to a combined stack associated with FGBOILER12.^{2,3,4} (“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” – paragraph 142, Act 451, Section 324.5503(b))

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. (R 336.1213(3)(b)(ii))

1. Every three (3) years, or more frequently upon request of the AQD, the permittee shall verify PM emission rates from EUBOILER1 by testing at the owner's expense, in accordance with the Department requirements. Testing shall be performed using an approved USEPA Method listed in 40 CFR Part 60, Appendix A, Reference Method 17 (Determination of Particulate Emissions from Stationary Sources (In-stack Filtration Method)), Reference Method 5 or “MATS” 5, or other acceptable test method(s). An alternate method, or a modification to the approved USEPA Method, may be specified in an AQD-approved Test Protocol. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. The permittee must submit a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test.² (R 336.1213(3), R 336.2001, R 336.2003, R 336.2004)
2. The permittee shall conduct a stack test for PM pursuant to the provisions found in Appendix 5: PM Emissions Testing and Monitoring Requirements. Subsequent stack tests for PM shall be conducted pursuant to the schedule and provisions found in Appendix 5: PM Emissions Testing and Monitoring Requirements.^{2,3,4} (“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” – paragraph 153, Act 451, Section 324.5503(b))
3. The permittee shall notify the AQD Technical Programs Unit Supervisor and the District Supervisor not less than 7 days of the time and place before performance tests are conducted.² (R 336.2001(3))
4. The permittee shall assess opacity using USEPA Reference Method 9 - “Visual Determination of the Opacity of Emissions from Stationary Sources,” upon the request of AQD.² (R 336.1301)

See Appendix 5

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. (R 336.1213(3)(b)(ii))

1. For purposes of determining compliance with the Rolling Average Emission Rates for NO_x and SO₂ as found in SC I.2, I.3, and I.4, the permittee shall install and operate CEMS in accordance with the procedures of 40 CFR Part 75, except that the NO_x and SO₂ emissions data need not be bias adjusted and the missing data substitution procedures of 40 CFR Part 75 shall not apply. If applicable, diluent capping (i.e., 5% CO₂) will be applied to the NO_x emission rate for any hours where the measured CO₂ concentration is less than 5% following the procedures in 40 CFR Part 75, Appendix F, Section 3.3.4.1.^{2,3,4} (“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” paragraphs 99 and 130, Act 451, Section 324.5503(b))

2. The permittee shall monitor unit level SO₂ concentrations and gas flow, using CEMS, as installed, maintained, and operated in accordance with 40 CFR Part 75.^{2,3,4} (**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 116, Act 451, Section 324.5503(b)**)
3. The permittee shall monitor gas flow, SO₂, CO₂, and NO_x emissions using CEMS, as installed, maintained, and operated in accordance with the provisions of 40 CFR Part 75.² (**R 336.1401, R 336.2101**)
4. The permittee shall monitor and record the opacity from each boiler using a Continuous Opacity Monitoring System (COMS), installed, operated and maintained in accordance with 40 CFR Part 60, Appendix B.² (**R 336.1301, R 336.2101**)

See Appendices 3-A, 3-B, and 3-D

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. (**R 336.1213(3)(c)(ii)**)
2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. (**R 336.1213(3)(c)(i)**)
3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. (**R 336.1213(4)(c)**)
4. The permittee shall submit any performance test reports, including RATA reports, to the AQD Technical Programs Unit and District Office, in a format approved by the AQD. (**R 336.1213(3)(c), R 336.2001(5)**)

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVBLR12	228 ²	400 ²	R 336.1225 R 336.2803 R 336.2804 40 CFR 52.21 (c) and (d)

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the acid rain permitting provisions of 40 CFR Part 72.1 to 72.94, as outlined in a complete Phase II, Acid Rain Permit issued by the AQD. Phase II, Acid Rain Permit No. MI-AR-1710-2020 is hereby incorporated into this ROP as Appendix 9. **(R 336.1902(1)(q))**
2. The permittee shall not allow the emission of an air pollutant to exceed the amount of any emission allowances that an affected source lawfully holds as of the allowance transfer deadline pursuant to R 336.1902(1)(q) and 40 CFR Part 72.9(c)(1)(i). **(R 336.1213(10))**
3. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule NO_x Annual Trading Program, as specified in 40 CFR Part 97, Subpart AAAAA, and identified in Appendix 10. **(40 CFR Part 97, Subpart AAAAA)**
4. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule NO_x Ozone Season Group 2 Trading Program, as specified in 40 CFR Part 97, Subpart EEEEE, and identified in Appendix 10. **(40 CFR Part 97, Subpart EEEEE)**
5. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule SO₂ Group 1 Trading Program, as specified in 40 CFR Part 97, Subpart CCCCC, and identified in Appendix 10. **(40 CFR Part 97, Subpart CCCCC)**
6. The permittee shall comply with applicable provisions of Act 451 Part 15 EMISSION LIMITATIONS AND PROHIBITIONS-MERCURY.² **(R 336.2503(1))**
7. The permittee shall comply with all applicable requirements of 40 CFR Part 64 as specified in FGBOILER12. **(40 CFR Part 64)**
8. The permittee shall comply with the applicable requirements of 40 CFR Part 63, Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units, as specified in FGMATS_U12.² **(40 CFR Part 63, Subpart UUUUU)**

Footnotes:

¹This condition is state only enforceable and was established pursuant to Rule 201(1)(b).

²This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

³This condition is federally enforceable and was originally established in the consent decree settling, "U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" and also pursuant to Act 451, Section 324.5503(b), and will remain in effect after termination of the consent decree.

⁴Definitions specific to this condition may be found in Appendix 1-B: Definitions Applicable to Specified Permit Conditions.

EUBOILER2 EMISSION UNIT CONDITIONS

DESCRIPTION

A 3560 MMBTU/hr wall-fired boiler with fuel oil startup capability. This emission unit is subject to 40 CFR Part 64 (CAM) and 40 CFR Part 63, Subpart UUUUU (MATS). All CAM requirements are in FGBOILER12, and all MATS requirements are in FGMATS_U12.

Flexible Group ID: FGBOILER12 and FGMATS_U12

POLLUTION CONTROL EQUIPMENT

Low-NOx burners,
Selective catalytic reduction (SCR),
Sorbent injection (ACI) (activated carbon or other sorbent for mercury control),
Dry sorbent injection (DSI) (hydrated lime or other sorbent), and
Pulse-jet fabric filter (PJFF) baghouse.

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Particulate matter (PM)	0.15 pound per 1,000 pounds exhaust gas, corrected to 50% excess air ²	Hourly	EUBOILER2	SC V.1 (FGBOILER12, SC VI.1, COMS)	R 336.1331(1)(c)
2. NO _x	0.100 pound per MMBTU heat input ^{2,3,4}	Based on a 30-day Rolling Average Emission Rate ^{2,3,4}	EUBOILER2	SC VI.1	"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 78; Act 451, Section 324.5503(b)
3. NO _x	0.080 pound per MMBTU heat input ^{2,3,4}	Based on a 90-day Rolling Average Emission Rate ^{2,3,4}	EUBOILER2	SC VI.1	"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 79; Act 451, Section 324.5503(b)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
4. SO ₂	0.320 pound per MMBTU heat input ^{2,3,4}	Based on a 365-day Rolling Average Emission Rate ^{2,3,4}	EUBOILER2	SC VI.1 SC VI.2	“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” paragraph 114; Act 451, Section 324.5503(b)
5. PM	0.015 pound per MMBTU heat input ^{2,3,4}	Hourly ^{2,3,4}	EUBOILER2	SC V.2 (FGBOILER12, SC VI.1, COMS)	“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” paragraph 145; Act 451, Section 324.5503(b)
6. SO ₂	1.67 pounds per MMBTU heat input ²	Monthly average, based on the average of the 31 previous operating days	EUBOILER2	SC VI.3	R 336.1401(3), Table 41
7. Opacity	20% ^{2,3,4}	Per 6-minute period except for one 6-minute period per hour of not more than 27% ^{2,3,4}	EUBOILER2	SC VI.4	“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” paragraph 151; Act 451, Section 324.5503(b)

8. The permittee shall comply with the System-Wide Annual NO_x Tonnage Limitations and System-Wide Annual SO₂ Tonnage Limitations specified in Appendix 11-A. Emissions from EUBOILER2 shall be counted toward the system-wide total emissions.^{2,3,4} (**“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” paragraphs 98 & 129, Act 451, Section 324.5503(b)**)
9. The permittee shall comply with the SO₂ and NO_x allowance surrender and super-compliance allowance provisions listed in Appendix 11-B: Allowance Provisions.^{2,3,4} (**“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” paragraphs 101-109 and 132-140, Act 451, Section 324.5503(b)**)

See Appendices 11-A and 11-B

II. MATERIAL LIMIT(S)

Material	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Coal – sulfur content	1.0% by weight, at a heat content of 12,000 BTU/lb ²	Monthly average, based on the average of the 31 previous operating days	EUBOILER2	SC VI.3	R 336.1401(3), Table 41

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall not operate EUBOILER2 unless a malfunction abatement plan (MAP) as described in Rule 911(2), for the emission control equipment (PJFF baghouse, ACI, DSI, and SCR) is implemented and maintained. The MAP shall, at a minimum, specify the following:
 - a. A complete preventative maintenance program including identification of the supervisory personnel responsible for overseeing the inspection, maintenance, and repair of air-cleaning devices, a description of the items or conditions that shall be inspected, the frequency of the inspections or repairs, and an identification of the major replacement parts that shall be maintained in inventory for quick replacement.
 - b. An identification of the source and air-cleaning device operating variables that shall be monitored to detect a malfunction or failure, the normal operating range of these variables, and a description of the method of monitoring or surveillance procedures.
 - c. A description of the corrective procedures or operational changes that shall be taken in the event of a malfunction or failure to achieve compliance with the applicable emission limits.

If at any time the MAP fails to address or inadequately addresses an event that meets the characteristics of a malfunction, the permittee shall amend the MAP within 45 days after such an event occurs. The permittee shall also amend the MAP within 45 days if new equipment is installed or upon request from the District Supervisor. The permittee shall submit the MAP and any amendments to the MAP to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the MAP or amended MAP shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.² **(R 336.1910, R 336.1911)**

2. The permittee shall continuously operate the PM Control Device for EUBOILER2 and use good air pollution control practices to maximize the PM emission reductions at all times when the unit is in operation. The requirements of Appendix 3-F shall be met.^{2,3,4} **(“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” – paragraph 141, Act 451, Section 324.5503(b))**
3. The permittee shall not operate the boiler, including startup and shutdown, unless the corresponding PJFF baghouse is installed and operating properly, in accordance with safe operating practices.² **(R 336.1910)**
4. The permittee shall not burn freeze conditioning/dust suppression agents unless PJFF baghouses are installed and operating properly, in accordance with safe operating practices.² **(R 336.1910)**

See Appendix 3-F

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall not operate EUBOILER2 unless the low-NOx burners, the SCR, DSI, ACI sorbent injection (for mercury control), and PJFF baghouse are installed, maintained, and operated in a satisfactory manner. Satisfactory manner includes operating and maintaining each control device in accordance with an approvable MAP for EUBOILER2 as required in SC III.1.² **(R 336.1910)**

2. The permittee shall not operate EUBOILER2 unless the SCR and PJFF baghouse are continuously operated.^{2,3,4} (“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” – paragraphs 77 and 145, Act 451, Section 324.5503(b))
3. The permittee shall not operate EUBOILER2 unless the DSI system is continuously operated.^{2,3,4} (“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” – paragraph 114, Act 451, Section 324.5503(b))
4. The permittee shall continuously operate the PM control devices being vented to a combined stack associated with FGBOILER12.^{2,3,4} (“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” – paragraph 142, Act 451, Section 324.5503(b))

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. (R 336.1213(3)(b)(ii))

1. Every three (3) years, or more frequently upon request of the AQD, the permittee shall verify PM emission rates from EUBOILER2 by testing at the owner's expense, in accordance with the Department requirements. Testing shall be performed using an approved USEPA Method listed in 40 CFR Part 60, Appendix A Reference Method 17 (Determination of Particulate Emissions from Stationary Sources (In-stack Filtration Method)), Reference Method 5, “MATS” Reference Method 5, or other acceptable test method(s). An alternate method, or a modification to the approved USEPA Method, may be specified in an AQD-approved Test Protocol. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. The permittee must submit a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test.² (R 336.1213(3), R 336.1201(3), R 336.2001, R 336.2003, R 336.2004)
2. The permittee shall conduct a stack test for PM pursuant to the provisions found in Appendix 5: PM Emissions Testing and Monitoring Requirements. Subsequent stack tests for PM shall be conducted pursuant to the schedule and provisions found in Appendix 5: PM Emissions Testing and Monitoring Requirements.^{2,3,4} (“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” – paragraph 153, Act 451, Section 324.5503(b))
3. The permittee shall notify the AQD Technical Programs Unit Supervisor and the District Supervisor no less than 7 days prior to the anticipated test date.² (R 336.2001(3))
4. The permittee shall assess opacity using USEPA Reference Method 9 - “Visual Determination of the Opacity of Emissions from Stationary Sources”, upon the request of AQD.² (R 336.1301)

See Appendix 5

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. (R 336.1213(3)(b)(ii))

1. For purposes of determining compliance with the Rolling Average Emission Rates for NO_x and SO₂ as found in SC I.2, I.3, and I.4., the permittee shall install and operate CEMS in accordance with the procedures of 40 CFR Part 75, except that the NO_x and SO₂ emissions data need not be bias adjusted and the missing data substitution procedures of 40 CFR Part 75 shall not apply. If applicable, diluent capping (i.e., 5% CO₂) will be applied to the NO_x emission rate for any hours where the measured CO₂ concentration is less than 5% following the procedures in 40 CFR Part 75, Appendix F, Section 3.3.4.1.^{2,3,4} (“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” paragraphs 99 and 130, Act 451, Section 324.5503(b))
2. The permittee shall monitor SO₂ concentrations and gas flow using CEMS, as installed, maintained, and operated in accordance with 40 CFR Part 75.^{2,3,4} (“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” paragraph 116, Act 451, Section 324.5503(b))

3. The permittee shall monitor gas flow, SO₂, CO₂, and NO_x emissions using CEMS, as installed, maintained, and operated in accordance with the provisions of 40 CFR Part 75.² **(R 336.1401, R 336.2101)**
4. The permittee shall monitor and record the opacity from each boiler using a Continuous Opacity Monitoring System (COMS), installed, operated and maintained in accordance with 40 CFR Part 60, Appendix B.² **(R 336.1301, R 336.2101)**

See Appendices 3-A, 3-B, and 3-D

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**
2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**
3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**
4. The permittee shall submit any performance test reports, including RATA reports to the AQD Technical Programs Unit and District Office, in a format approved by the AQD. **(R 336.1213(3)(c), R 336.2001(5))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVBLR12	228 ²	400 ²	R 336.1225 R 336.2803 R 336.2804 40 CFR 52.21 (c) and (d)

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the acid rain permitting provisions of 40 CFR 72.1 to 72.94, as outlined in a complete Phase II, Acid Rain Permit issued by the AQD. Phase II, Acid Rain Permit No. MI-AR-1710-2020 is hereby incorporated into this ROP as Appendix 9. **(R 336.1902(1)(q))**
2. The permittee shall not allow the emission of an air pollutant to exceed the amount of any emission allowances that an affected source lawfully holds as of the allowance transfer deadline pursuant to R 336.1902(1)(q) and 40 CFR 72.9(c)(1)(i). **(R 336.1213(10))**
3. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule NO_x Annual Trading Program, as specified in 40 CFR Part 97, Subpart AAAAA, and identified in Appendix 10. **(40 CFR Part 97, Subpart AAAAA)**

4. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule NO_x Ozone Season Group 2 Trading Program, as specified in 40 CFR Part 97, Subpart EEEEE, and identified in Appendix 10. **(40 CFR Part 97, Subpart EEEEE)**
5. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule SO₂ Group 1 Trading Program, as specified in 40 CFR Part 97, Subpart CCCCC, and identified in Appendix 10. **(40 CFR Part 97, Subpart CCCCC)**
6. The permittee shall comply with applicable provisions of Act 451 Part 15 EMISSION LIMITATIONS AND PROHIBITIONS—MERCURY.² **(R 336.2503(1))**
7. The permittee shall comply with all applicable requirements of 40 CFR Part 64 as specified in FGBOILER12. **(40 CFR Part 64)**
8. The permittee shall comply with the applicable requirements of 40 CFR Part 63, Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units, as specified in FGMATS_U12.² **(40 CFR Part 63, Subpart UUUUU)**

See Appendices 11-A and 11-B

Footnotes:

¹This condition is state only enforceable and was established pursuant to Rule 201(1)(b).

²This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

³This condition is federally enforceable and was originally established in the consent decree settling, “U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” and also pursuant to Act 451, Section 324.5503(b), and will remain in effect after termination of the consent decree.

⁴Definitions specific to this condition may be found in Appendix 1-B: Definitions Applicable to Specified Permit Conditions.

EUBOILER3 EMISSION UNIT CONDITIONS

DESCRIPTION

An 8240 MMBTU/hr dry bottom, wall-fired boiler with fuel oil startup capability. This emission unit is subject to 40 CFR Part 63, Subpart UUUUU (MATS). The MATS requirements are in FGMATS_U3.

Flexible Group ID: FGMATS_U3

POLLUTION CONTROL EQUIPMENT

Low-NOx burners,
Selective catalytic reduction (SCR),
Sorbent injection (ACI) (activated carbon or other sorbent for mercury control),
Spray dry absorber (SDA), and
Pulse-jet fabric filter (PJFF) baghouse.

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Opacity	20% ²	Per 6-minute period except for one 6-minute period per hour of not more than 27%	EUBOILER3	SC VI.2	40 CFR 60.42(a)(2), R 336.1301
2. Opacity	20% ^{2,3,4}	Per 6-minute period except for one 6-minute period per hour of not more than 27%	EUBOILER3	SC VI.2	“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14- 13580, E.D. MICH., 2014” paragraph 151; Act 451, Section 324.5503(b)
3. PM	0.10 pound per MMBTU heat input ²	Hourly	EUBOILER3	SC V.1 SC VI.2 SC VI. 4	40 CFR 60.42(a)(1)
4. PM	370 pounds per hour ²	Hourly	EUBOILER3	SC V.1 SC VI.2 SC VI.4	R 336.1205(3)
5. PM	1,080 tons per year ²	Based on a 12-month rolling time period as determined at the end of each calendar month	EUBOILER3	SC V.1 SC VI.2 SC VI.4	R 336.1205(3)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
6. PM	0.015 pound per MMBTU heat input ^{2,3,4}	Based on a 3-hr rolling average in accordance with SC V.4 and SC VI.4 ^{2,3,4}	EUBOILER3	SC V.3, SC V.4 (if applicable) SC VI.4	“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14- 13580, E.D. MICH., 2014” paragraph 146; Act 451, Section 324.5503(b)
7. SO ₂	1.2 pounds per MMBTU heat input ²	Continuous	EUBOILER3	SC VI.1	40 CFR 60.43(a)(2)
8. SO ₂	10,500 pounds per hour ²	Based on a daily average	EUBOILER3	SC VI.1	R 336.1205(3)
9. SO ₂	31,650 tons per year ²	Based on a 12-month rolling time period as determined at the end of each calendar month	EUBOILER3	SC VI.1	R 336.1205(3)
10. SO ₂	0.085 pound per MMBTU heat input ^{2,3,4}	Based on a 30-day Rolling Average ^{2,3,4}	EUBOILER3	SC VI.3	“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14- 13580, E.D. MICH., 2014” paragraph 112; Act 451, Section 324.5503(b)
11. SO ₂	0.070 pound per MMBTU heat input ^{2,3,4}	Based on a 365-day Rolling Average Emission Rate ^{2,3,4}	EUBOILER3	SC VI.3	“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14- 13580, E.D. MICH., 2014” paragraph 112; Act 451, Section 324.5503(b)
12. NO _x	0.70 pound per MMBTU heat input ²	Per 3-hour rolling time period, as determined each hour the boiler operates	EUBOILER3	SC VI.1	40 CFR 60.44(a)(3)
13. NO _x	6,130 pounds per hour ²	Based on a daily average	EUBOILER3	SC VI.1	R 336.1205(3)
14. NO _x	18,750 tons per year ²	Based on a 12-month rolling time period as determined at the end of each calendar month	EUBOILER3	SC VI.1	R 336.1205(3)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
15. NOx	0.100 pound per MMBTU heat input ^{2,3,4}	Based on a 30-day Rolling Average Emission Rate ^{2,3,4}	EUBOILER3	SC VI.3	“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14- 13580, E.D. MICH., 2014” paragraph 81; Act 451, Section 324.5503(b)
16. NOx	0.080 pound per MMBTU heat input ^{2,3,4}	Based on a 90-day Rolling Average Emission Rate ^{2,3,4}	EUBOILER3	SC VI.3	“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14- 13580, E.D. MICH., 2014” paragraph 82; Act 451, Section 324.5503(b)

17. The permittee shall comply with the System-Wide Annual NO_x Tonnage Limitations and System-Wide Annual SO₂ Tonnage Limitations specified in Appendix 11-A. Emissions from EUBOILER3 shall be counted toward the system-wide total emissions.^{2,3,4} (**“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” paragraphs 98 & 129, Act 451, Section 324.5503(b)**)

18. The permittee shall comply with the SO₂ and NO_x allowance surrender and super-compliance allowance provisions listed in Appendix 11-B: Allowance Provisions.^{2,3,4} (**“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” paragraphs 101-109 and 132-140, Act 451, Section 324.5503(b)**)

See Appendix 11-A and Appendix 11-B

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

- The permittee shall not burn freeze conditioning/dust suppression agents unless the boiler and corresponding particulate control device are operating properly.² (**R 336.1910**)
- The permittee shall not operate the boiler, including startup and shutdown, unless the corresponding PJFF baghouse is installed and operating properly, in accordance with safe operating practices.² (**R 336.1910**)
- The permittee shall not operate EUBOILER3 unless a malfunction abatement plan (MAP) as described in Rule 911(2), for emission control equipment (PJFF baghouse, ACI, SDA, and SCR) is implemented and maintained. The MAP shall, at a minimum, specify the following:
 - A complete preventative maintenance program including identification of the supervisory personnel responsible for overseeing the inspection, maintenance, and repair of air-cleaning devices, a description of the items or conditions that shall be inspected, the frequency of the inspections or repairs, and an identification of the major replacement parts that shall be maintained in inventory for quick replacement.

- b. An identification of the source and air-cleaning device operating variables that shall be monitored to detect a malfunction or failure, the normal operating range of these variables, and a description of the method of monitoring or surveillance procedures.
- c. A description of the corrective procedures or operational changes that shall be taken in the event of a malfunction or failure to achieve compliance with the applicable emission limits.

If at any time the MAP fails to address or inadequately addresses an event that meets the characteristics of a malfunction, the permittee shall amend the MAP within 45 days after such an event occurs. The permittee shall also amend the MAP within 45 days if new equipment is installed or upon request from the District Supervisor. The permittee shall submit the MAP and any amendments to the MAP to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the MAP or amended MAP shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.² **(R 336.1910, R 336.1911)**

4. The permittee shall comply with all provisions of the federal Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced after August 17, 1971, as specified in 40 CFR Part 60, Subparts A and D, as they apply to EUBOILER3.² **(40 CFR Part 60, Subparts A and D)**
5. The permittee shall continuously operate the PM Control Device for EUBOILER3 and use good air pollution control practices to maximize the PM emission reductions at all times when the unit is in operation. The requirements of Appendix 3-F shall be met.^{2,3,4} **(“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” – paragraph 141, Act 451, Section 324.5503(b))**

See Appendix 3-F

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall not operate EUBOILER3 unless the low-NOx burners, the SCR, SDA, ACI sorbent injection (for mercury control), and PJFF baghouse are installed, maintained, and operated in a satisfactory manner. Satisfactory manner includes operating and maintaining each control device in accordance with an approvable MAP for EUBOILER3 as required in SC III.5.² **(R 336.1910)**
2. The permittee shall not operate EUBOILER3 unless the SCR is Continuously Operated.^{2,3,4} **(“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” – paragraph 80, Act 451, Section 324.5503(b))**
3. The permittee shall not operate EUBOILER3 unless the SDA and PJFF baghouse units are Continuously Operated.^{2,3,4} **(“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” – paragraphs 112 and 146, Act 451, Section 324.5503(b))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. Every three (3) years, or more frequently upon request of the AQD, the permittee shall verify PM emission rates from EUBOILER3 by testing at the owner's expense, in accordance with the Department requirements. Testing shall be performed using an approved USEPA Method listed in 40 CFR Part 60, Appendix A, Reference Method 17 (Determination of Particulate Emissions from Stationary Sources (in-stack Filtration Method) Reference Method 5, “MATS” Reference Method 5, or other acceptable test method(s). An alternate method, or a modification to the approved USEPA Method, may be specified in an AQD-approved Test Protocol. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. The permittee must submit a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test.² **(R 336.2001, R 336.2003, R 336.2004)**

2. The permittee shall notify the AQD no less than 7 days prior to the anticipated test date.² **(R 336.2001(3))**
3. The permittee shall conduct a stack test for PM pursuant to the provisions found in Appendix 5: PM Emissions Testing and Monitoring Requirements. Subsequent stack tests for PM shall be conducted pursuant to the schedule and provisions found in Appendix 5: PM Emissions Testing and Monitoring Requirements.^{2,3,4} **(“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” – paragraph 153, Act 451, Section 324.5503(b))**
4. As an alternative to the requirements of SC V.3 PM stack testing, the permittee may forego stack testing and instead demonstrate continuous compliance with SC I.7 PM filterable emission limit by using the PM CEMS pursuant to conditions contained in Appendix 5: PM Emissions Testing and Monitoring Requirements, and Appendix 3-E: PM CEMS.^{2,3,4} **(“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” – paragraph 157, Act 451, Section 324.5503(b))**

See Appendices 3-E and 5

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall monitor gas flow, SO₂, CO₂, and NO_x emissions using CEMS, as installed, maintained, and operated in accordance with the provisions of 40 CFR Part 75.² **(R 336.1205(3), R 336.2101, 40 CFR Part 60)**
2. The permittee shall monitor and record the opacity from the boiler using a Continuous Opacity Monitoring System (COMS), installed, operated and maintained in accordance with 40 CFR Part 60, Appendix B.² **(R 336.1301, R 336.2101, 40 CFR 60.42(a)(2))**
3. For purposes of determining compliance with the Rolling Average Emission Rates for NO_x and SO₂ as found in SC I.10, I.11, I.15, and I.16, the permittee shall install and operate CEMS in accordance with the procedures of 40 CFR Part 75, except that the NO_x and SO₂ emissions data need not be bias adjusted and the missing data substitution procedures of 40 CFR Part 75 shall not apply. If applicable, diluent capping (i.e., 5% CO₂) will be applied to the NO_x emission rate for any hours where the measured CO₂ concentration is less than 5% following the procedures in 40 CFR Part 75, Appendix F, Section 3.3.4.1.^{2,3,4} **(“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” paragraphs 99 and 130, Act 451, Section 324.5503(b))**
4. The permittee shall install and continuously operate a PM CEMS pursuant to the conditions contained in Appendix 3-E: PM CEMS.^{2,3,4} **(“U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014” paragraphs 159, 163, Act 451, Section 324.5503(b))**

See Appendices 3-A through 3-F

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**
2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**
3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**
4. The permittee shall submit any performance test reports, including RATA reports to the AQD Technical Programs Unit and District Office, in a format approved by the AQD. **(R 336.1213(3)(c), R 336.2001(5))**

5. Quarterly reporting of monthly excess sulfur dioxide, and nitrogen oxide emissions (including the nature and cause of the periods of excess emissions), and of the dates and times of the monitoring systems being inoperative. Each quarterly report is due within 30 days of the calendar quarter reporting period. **(R 336.2170)**
6. Quarterly reporting of excess opacity emissions (including the nature and cause of the periods of excess emissions), and of the dates and times of the monitoring systems being inoperative. Each quarterly report is due within 30 days of the calendar quarter reporting period. **(R 336.2170)**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVBLR3	327 ²	642 ²	R 336.1201(3)

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the acid rain permitting provisions of 40 CFR 72.1 to 72.94, as outlined in a complete Phase II, Acid Rain Permit issued by the AQD. Phase II, Acid Rain Permit No. MI-AR-1710-2020 is hereby incorporated into this ROP as Appendix 9. **(R 336.1902(1)(q))**
2. The permittee shall not allow the emission of an air pollutant to exceed the amount of any emission allowances that an affected source lawfully holds as of the allowance transfer deadline pursuant to R 336.1902(1)(q) and 40 CFR 72.9(c)(1)(i). **(R 336.1213(10))**
3. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule NO_x Annual Trading Program, as specified in 40 CFR Part 97, Subpart AAAAA, and identified in Appendix 10. **(40 CFR Part 97, Subpart AAAAA)**
4. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule NO_x Ozone Season Group 2 Trading Program, as specified in 40 CFR Part 97, Subpart EEEEE, and identified in Appendix 10. **(40 CFR Part 97, Subpart EEEEE)**
5. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule SO₂ Group 1 Trading Program, as specified in 40 CFR Part 97, Subpart CCCCC, and identified in Appendix 10. **(40 CFR Part 97, Subpart CCCCC)**
6. The permittee shall comply with applicable provisions of Act 451 Part 15 EMISSION LIMITATIONS AND PROHIBITIONS—MERCURY.² **(R 336.2503(1))**
7. The permittee shall comply with the applicable requirements of 40 CFR Part 63, Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units as specified in FGMATS_U3.² **(40 CFR Part 63, Subpart UUUUU)**

Footnotes:

¹This condition is state only enforceable and was established pursuant to Rule 201(1)(b).

²This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

³This condition is federally enforceable and was originally established in the consent decree settling, "U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" and also pursuant to Act 451, Section 324.5503(b), and will remain in effect after termination of the consent decree.

⁴Definitions specific to this condition may be found in Appendix 1-B: Definitions Applicable to Specified Permit Conditions.

EUCOALHAND EMISSION UNIT CONDITIONS

DESCRIPTION

The coal handling facility consists of: (2) dumper buildings, transfer conveyors, transfer building, breaker house, bunker rooms, and the coal pile storage area itself.

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

Enclosures, 11 baghouses, dust suppression, telescopic spouts. The Dust Collectors serving the Unit 1 and 2 (DC10), and Unit 3 (DC1) dumper houses, and Coal yard dust hopper (DC11) are subject to 40 CFR Part 64 (CAM).

Dust collectors serving the breaker house (DC4), bunker houses (DC 5, 6, 7) and the reclaim hopper (DC9) are subject to the New Source Performance Standard 40 CFR Part 60, Subpart Y. (Initial performance testing has been completed.)

Dust collectors serving the reclaim (DC2) and transfer house (DC3A, DC3B) are subject to Michigan Rule 336.1301.

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. PM	0.10 pound per 1,000 pounds exhaust gas, on a dry basis	At all times, as verifiable through any requested stack testing	Each discharge point	SC IV.1 SC VI.1 Through SC VI.8 (Proper maintenance and operation of the baghouses)	R 336.1331(1)(a), Table 31(j)
2. Opacity	20%	6-minute average	Discharge points for dust collectors DC4, DC5, DC6, DC7, and DC9	SC IV.1 SC VI.1 Through SC VI.8 (Proper maintenance and operation of the baghouses)	40 CFR 60.252(c) (NSPS, Subpart Y)
3. Opacity	20%	6-minute average	Discharge points for dust collectors DC1, DC2, DC3A, DC3B, DC10, and DC11,	SC IV.1 SC VI.1 Through SC VI.8 (Proper maintenance and operation of the baghouses)	R 336.1301(1)(a)

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall not operate a process portion unless the particulate matter control device controlling the portion is installed and operating properly. **(R 336.1910)**
2. The permittee shall operate all coal handling equipment in accordance with the most recent facility Fugitive Dust Control Plan as approvable by the AQD District Supervisor. **(R 336.1213(3))**
3. The permittee shall not operate EUCOALHAND unless a malfunction abatement plan (MAP) as described in Rule 911(2), for emission control equipment is implemented and maintained. The MAP shall, at a minimum, specify the following:
 - a. A complete preventative maintenance program including identification of the supervisory personnel responsible for overseeing the inspection, maintenance, and repair of air-cleaning devices, a description of the items or conditions that shall be inspected, the frequency of the inspections or repairs, and an identification of the major replacement parts that shall be maintained in inventory for quick replacement.
 - b. An identification of the source and air-cleaning device operating variables that shall be monitored to detect a malfunction or failure, the normal operating range of these variables, and a description of the method of monitoring or surveillance procedures.
 - c. A description of the corrective procedures or operational changes that shall be taken in the event of a malfunction or failure to achieve compliance with the applicable emission limits.

If at any time the MAP fails to address or inadequately addresses an event that meets the characteristics of a malfunction, the permittee shall amend the MAP within 45 days after such an event occurs. The permittee shall also amend the MAP within 45 days if new equipment is installed or upon request from the District Supervisor. The permittee shall submit the MAP and any amendments to the MAP to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the MAP or amended MAP shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits. **(R 336.1910, R 336.1911)**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. Each particulate matter control device shall be equipped with pressure drop measurement devices and associated alarm system.² **(R 336.1201(3), R 336.1213(3))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall assess opacity using USEPA Reference Method 9 - "Visual Determination of the Opacity of Emissions from Stationary Sources", upon the request of AQD. **(R 336.1213(3))**
2. Upon request of the AQD District Supervisor, the permittee shall verify PM emission rates from EUCOALHAND by testing at the owner's expense, in accordance with the Department requirements. Testing shall be performed using an approved USEPA Method listed in 40 CFR Part 60, Appendix A; Part 10 of the Michigan Air Pollution Control Rules. An alternate method, or a modification to the approved USEPA Method, may be specified in an AQD-approved Test Protocol. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. The permittee must submit a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test. **(R 336.1213(3), R 336.2001, R 336.2003, R 336.2004)**

3. The permittee shall notify the AQD Technical Programs Unit Supervisor and the District Supervisor not less than 7 days of the time and place before performance tests are conducted. **(R 336.1213(3))**

See Appendix 5

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall conduct and record non-certified visible emissions observations for the dust collectors servicing EUBOILER 1, EUBOILER2 (DC10) and EUBOILER3 (DC1) dumper houses and Coal Yard dust hopper DC(11) once per day when operating, as the primary indicator of the proper functioning of each fabric filter dust collector. If visible emissions are observed, the permittee shall document the visible emissions, including the duration, and continue to observe the source of the visible emissions until no visible emissions are observed. The permittee shall initiate corrective actions as quickly as possible upon the detection of visible emissions. If there is a break in the visible emissions observations, it will be assumed that visible emissions continue to occur during any break in observations. The appropriate range of visible emissions defining proper functioning of each fabric filter dust collector is no visible emissions. **(40 CFR 64.6(c)(1)(i), (ii), and (iii))**
2. An excursion is the observation of visible emissions for the dust collectors serving EUBOILER1 and EUBOILER2 (DC10) or EUBOILER3 (DC1) dumper house or the coal yard dust hopper (DC11) for a duration exceeding one (1) hour. **(40 CFR 64.6(c)(2))**
3. The permittee shall properly maintain the monitoring system, including keeping necessary parts for routine repair of the monitoring equipment. **(40 CFR 64.7(b))**
4. Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions or other measures as specified in the MAP. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). **(40 CFR 64.7(d))**
5. Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. **(40 CFR 64.6(c)(3), 40 CFR 64.7(c))**
6. Any formal compliance determinations with the opacity limit established in 40 CFR 60.252(c) shall utilize Method 9 and the procedures in 40 CFR 60.11. **(40 CFR 60.254(b)(2))**
7. The permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan and any activities undertaken to implement a quality improvement plan, and other information such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions. **(40 CFR 64.9(b)(1))**

8. The permittee shall perform, and document non-certified visible emissions observations from dust collectors DC4, DC5, DC6, DC7, and DC9 as required in I.2 on a daily basis when EUCOALHAND is operating. If during the observation there are any visible emissions detected from an emission point, then corrective procedures as defined in the MAP shall be implemented. Records of the non-certified visible emissions observations, USEPA Method 9 observations that are performed, the reason for any visible emissions observed, and any corrective actions taken, shall be kept on file and in a format acceptable to the AQD. **(R 336.1213(3))**

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**
2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**
3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**
4. Each semiannual report of monitoring deviations shall include summary information on the number, duration, and cause of exceedances/excursions in the reporting period; and the corrective actions taken in response. If there were no excursions and/or exceedances in the reporting period, then this report shall include a statement that there were no excursions and/or exceedances. **(40 CFR 64.9(a)(2)(i))**
5. Each semiannual report of monitoring deviations shall include summary information on monitor downtime. If there were no periods of monitor downtime in the reporting period, then this report shall include a statement that there were no periods of monitor downtime. **(40 CFR 64.9(a)(2)(ii))**
6. Each semiannual report of monitoring deviations shall include a description of the actions taken to implement a Quality Improvement Plan (QIP) during the reporting period, if appropriate. If a QIP has been completed, the report shall include documentation that the QIP has been implemented, and a discussion pertaining to whether the QIP implementation has reduced the likelihood of excursions or exceedances. **(40 CFR 64.9(a)(2)(iii))**
7. The permittee shall submit any performance test reports, except for Method 9, to the AQD Technical Programs Unit and District Office, in a format approved by the AQD. **(R 336.1213(3)(c), R 336.2001(5))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

1. The permittee shall otherwise comply with the applicable requirements of 40 CFR Part 60 ("Standards of Performance for New Stationary Sources"), Subparts A ("General Provisions") and Y ("Standards of Performance for Coal Preparation Plants"). **(40 CFR Part 60, Subparts A and Y)**
2. The permittee shall comply with all applicable requirements of 40 CFR Part 64. **(40 CFR Part 64)**

3. If the permittee identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the permittee shall promptly notify the AQD and if necessary, submit a proposed modification of the ROP and CAM Plan to address the necessary monitoring changes. Such a modification may include but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters. **(40 CFR 64.7(e))**

Footnotes:

¹ This condition is state only enforceable and was established pursuant to Rule 201(1)(b).

² This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUSDA_U3 EMISSION UNIT CONDITIONS

DESCRIPTION

Lime preparation operations for Boiler 3 that support the SDA including storage silos, vertical ball mills, and lime slurry transfer and product tanks.

SDA operations for Boiler 3 including lime slurry atomizer head tanks, recycle silos, recycle mix tanks, and recycle slurry storage tanks. The two recycle silos are subject to 40 CFR Part 64 Compliance Assurance Monitoring (CAM).

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

Silos are controlled by bin vent filters.

Ball mills emissions controlled by spray scrubbers (mill scrubbers).

Recycle mix tank emissions controlled by a spray scrubber.

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Opacity	5% ²	6-Minute average	Each bin vent filter in EUSDA_U3	SC VI.1	R 336.1301(1)(c)
2. Opacity	5% ²	6-Minute average	Each spray scrubber in EUSDA_U3	SC VI.1	R 336.1301(1)(c)
3. PM	0.004 gr / dscf of exhaust gases ²	Hourly	Each bin vent filter in EUSDA_U3	SC III.2 SC IV.1 SC V.1	R 336.1331(1)(c)
4. PM	0.01 gr / dscf of exhaust gases ²	Hourly	Each spray scrubber in EUSDA_U3	SC III.2 SC IV.1 SC V.1	R 336.1331(1)(c)
5. PM10	0.03 pph ²	Hourly	Each of the following bin vent filter emission points: SVLSS-BV3A SVLSS-BV3B SVLSS-BV3C	SC III.2 SC IV.1 SC V.1	R 336.2803 R 336.2804
6. PM2.5	0.03 pph ²	Hourly	Each of the following bin vent filter emission points: SVLSS-BV3A SVLSS-BV3B SVLSS-BV3C	SC III.2 SC IV.1 SC V.1	R 336.2803 R 336.2804
7. PM10	0.021 pph ²	Hourly	Each of the following spray scrubber emission points: SVVM-SS3A SVVM-SS3B SVVM-SS3C	SC III.2 SC IV.1 SC V.1	R 336.2803 R 336.2804

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
8. PM2.5	0.021 pph ²	Hourly	Each of the following spray scrubber emission points: SVVM-SS3A SVVM-SS3B SVVM-SS3C	SC III.2 SC IV.1 SC V.1	R 336.2803 R 336.2804
9. PM10	0.02 pph ²	Hourly	Each of the following bin vent filter emission points: SVRS-BV3A SVRS-BV3B (CAM Subject)	SC III.2 SC IV.1 SC V.1 SC VI.1 SC VI.2	R 336.2803 R 336.2804
10. PM2.5	0.02 pph ²	Hourly	Each of the following bin vent filter emission points: SVRS-BV3A SVRS-BV3B (CAM Subject)	SC III.2 SC IV.1 SC V.1 SC VI.1 SC VI.2	R 336.2803 R 336.2804
11. PM10	0.024 pph ²	Hourly	Each of the following spray scrubber emission points: SVMT-SS3A1 SVMT-SS3B1 SVMT-SS3A2 SVMT-SS3B2	SC III.2 SC IV.1 SC V.1	R 336.2803 R 336.2804
12. PM2.5	0.024 pph ²	Hourly	Each of the following spray scrubber emission points: SVMT-SS3A1 SVMT-SS3B1 SVMT-SS3A2 SVMT-SS3B2	SC III.2 SC IV.1 SC V.1	R 336.2803 R 336.2804

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The Campbell Complex fugitive dust plan shall be updated as necessary and kept at the facility. If at any time the fugitive dust control program fails to address or inadequately addresses a dusting event, the permittee shall amend the fugitive dust control program within 45 days after such an event occurs. The permittee shall also amend the fugitive dust control program within 45 days, if new equipment is installed or upon request from the AQD District Supervisor. The permittee shall submit the fugitive dust control program and any amendments to the fugitive dust control program to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the fugitive dust control program or amended fugitive dust control program shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.² **(R 336.1372, R 336.2803, R 336.2804, Act 451, Section 324.5524)**
2. The permittee shall not operate EUSDA_U3 unless a malfunction abatement plan (MAP) as described in Rule 911(2), for operation of the process and emission control equipment, is implemented updated as necessary, and kept at the facility. If at any time the MAP fails to address or inadequately addresses an event that meets

the characteristics of a malfunction, the permittee shall amend the MAP within 45 days after such an event occurs. The permittee shall also amend the MAP within 45 days, if new equipment is installed or upon request from the AQD District Supervisor. The permittee shall submit the MAP and any amendments to the MAP to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the MAP or amended MAP shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.² **(R 336.1910, R 336.1911)**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall not operate any portion of EUSDA_U3 unless the associated enclosures, bin vent filters and spray scrubbers are installed, maintained and operated in a satisfactory manner. Satisfactory manner includes operating and maintaining each control device in accordance with an approved MAP for EUSDA_U3 as required in SC III.2.² **(R 336.1910, R 336.1911, R 336.2803, R 336.2804)**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. Upon request of the AQD District Supervisor, the permittee shall verify PM, PM10, and PM2.5 emission rates from EUSDA_U3 by testing at owner's expense, in accordance with the Department requirements. Testing shall be performed using an approved USEPA Method listed in:

Pollutant	Test Method Reference
PM	40 CFR Part 60, Appendix A; Part 10 of the Michigan Air Pollution Control Rules
PM10/PM2.5	40 CFR Part 51, Appendix M

An alternate method, or a modification to the approved USEPA Method, may be specified in an AQD-approved Test Protocol. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. The permittee must submit a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test. **(R 336.1213(3), R 336.2001, R 336.2003, R 336.2004)**

The permittee shall notify the AQD Technical Programs Unit Supervisor and the District Supervisor not less than 7 days of the time and place before performance tests are conducted. **(R 336.1213(3))**

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall perform, and document non-certified visible emissions observations as required in SC I.1 and I.2 on a daily basis when EUSDA_U3 is operating. If during the observation there are any visible emissions detected from an emission point, then corrective procedures as defined in the MAP shall be implemented. Records of the non-certified visible emissions observations, USEPA Method 9 observations that are performed, the reason for any visible emissions observed, and any corrective actions taken, shall be kept on file and in a format acceptable to the AQD.² **(R 336.1301(1)(c))**
2. The permittee shall conduct and record non-certified visible emissions observations the Recycle Silo bin vent filters (SVRS-BV3A, SVRS-BV3B) once per day when operating, as the primary indicator of the proper functioning of each bin vent filter for EUSDA_U3. If visible emissions are observed, the permittee shall document the visible emissions, including duration, and continue to observe the source of the visible emissions until no visible emissions are observed. The permittee shall initiate corrective actions as quickly as possible upon the detection of visible emissions. If there is a break in the visible emissions observations, it will be assumed that visible emissions continue to occur during any break in observations. The appropriate range of visible emissions defining proper functioning of each bin vent filter is no visible emissions. **(40 CFR 64.6(c)(1)(i), (ii), and (iii))**
3. An excursion is the observation of visible emissions for a duration exceeding one (1) hour. **(40 CFR 64.6(c)(2))**

4. Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions or in accordance with the MAP. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). **(40 CFR 64.7(d))**
5. Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. **(40 CFR 64.6(c)(3), 40 CFR 64.7(c))**
6. The permittee shall properly maintain the monitoring system, including keeping necessary parts for routine repair of the monitoring equipment. **(40 CFR 64.7(b))**
7. The permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan and any activities undertaken to implement a quality improvement plan, and other information such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions. **(40 CFR 64.9(b)(1))**

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**
2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**
2. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**
3. Each semiannual report of monitoring and deviations shall include summary information on the number, duration and cause of excursions and/or exceedances and the corrective actions taken. If there were no excursions and/or exceedances in the reporting period, then this report shall include a statement that there were no excursions and/or exceedances. **(40 CFR 64.9(a)(2)(i))**
4. Each semiannual report of monitoring and deviations shall include summary information on monitor downtime. If there were no periods of monitor downtime in the reporting period, then this report shall include a statement that there were no periods of monitor downtime. **(40 CFR 64.9(a)(2)(ii))**
5. Each semiannual report shall include a Quality Improvement Plan (QIP) during the reporting period, if appropriate. If a QIP has been completed, the report shall include documentation that the QIP has been implemented, and a discussion pertaining to whether the QIP implementation has reduced the likelihood of excursions or exceedances. **(40 CFR 64.9(a)(2)(iii))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVLSS-BV3A	4.3 ²	135 ²	R 336.2803 R 336.2804
2. SVLSS-BV3B	4.3 ²	135 ²	R 336.2803 R 336.2804
3. SVLSS-BV3C	4.3 ²	135 ²	R 336.2803 R 336.2804
4. SVVM-SS3A	11.4 ²	52 ²	R 336.2803 R 336.2804
5. SVVM-SS3B	11.4 ²	52 ²	R 336.2803 R 336.2804
6. SVVM-SS3C	11.4 ²	52 ²	R 336.2803 R 336.2804
7. SVRS-BV3A	6.1 ²	126 ²	R 336.2803 R 336.2804
8. SVRS-BV3B	6.1 ²	126 ²	R 336.2803 R 336.2804
9. SVMT-SS3A1	6.1 ²	58 ²	R 336.2803 R 336.2804
10. SVMT-SS3B1	6.1 ²	58 ²	R 336.2803 R 336.2804
11. SVMT-SS3A2	6.1 ²	58 ²	R 336.2803 R 336.2804
12. SVMT-SS3B2	6.1 ²	58 ²	R 336.2803 R 336.2804

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with all applicable requirements of 40 CFR Part 64. **(40 CFR Part 64)**
2. If the permittee identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the permittee shall promptly notify the AQD and if necessary, submit a proposed modification of the ROP and CAM Plan to address the necessary monitoring changes. Such a modification may include but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters. **(40 CFR 64.7(e))**

Footnotes:

¹ This condition is state only enforceable and was established pursuant to Rule 201(1)(b).

² This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUDSI_U12 EMISSION UNIT CONDITIONS

DESCRIPTION

Dry Sorbent Injection (DSI) Material Handling for Boilers 1 and 2. Includes sorbent silos (hydrated lime or other sorbent) and pneumatic transfer.

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

Bin vent filters

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Opacity	5% ²	6- Minute Average	Each bin vent filter in EUDSI_U12	SC VI.1	R 336.1301(1)(c)
2. PM	0.004 gr / dscf of exhaust gases ²	Hourly	Each bin vent filter in EUDSI_U12	SC III.2 SC VI.1	R 336.1331(1)(c)
3. PM10	0.08 pph ²	Hourly	Each of the following bin vent filter emission points: SVLSS-BV1A SVLSS-BV1B SVLSS-BV1C SVLSS-BV2A SVLSS-BV2B SVLSS-BV2C	SC III.2 SC VI.1	R 336.2803 R 336.2804
4. PM2.5	0.08 pph ²	Hourly	Each of the following bin vent filter emission points: SVLSS-BV1A SVLSS-BV1B SVLSS-BV1C SVLSS-BV2A SVLSS-BV2B SVLSS-BV2C	SC III.2 SC VI.1	R 336.2803 R 336.2804

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

- The Campbell Complex fugitive dust plan shall be updated as necessary and kept at the facility. If at any time the fugitive dust control program fails to address or inadequately addresses a dusting event, the permittee shall amend the fugitive dust control program within 45 days after such an event occurs. The permittee shall also amend the fugitive dust control program within 45 days, if new equipment is installed or upon request from the AQD District Supervisor. The permittee shall submit the fugitive dust control program and any amendments to the fugitive dust control program to the AQD District Supervisor for review and approval. If the AQD does not

notify the permittee within 90 days of submittal, the fugitive dust control program or amended fugitive dust control program shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.² **(R 336.1372, R 336.2803, R 336.2804, Act 451, Section 324.5524)**

2. The permittee shall not operate EUDSI_U12 unless a malfunction abatement plan (MAP) as described in Rule 911(2), for operation of the process and emission control equipment, is implemented updated as necessary, and kept at the facility. If at any time the MAP fails to address or inadequately addresses an event that meets the characteristics of a malfunction, the permittee shall amend the MAP within 45 days after such an event occurs. The permittee shall also amend the MAP within 45 days, if new equipment is installed or upon request from the AQD District Supervisor. The permittee shall submit the MAP and any amendments to the MAP to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the MAP or amended MAP shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.² **(R 336.1910, R 336.1911)**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall not operate any portion of EUDSI_U12 unless the associated enclosures and bin vent filters are installed, maintained and operated in a satisfactory manner. Satisfactory manner includes operating and maintaining each control device in accordance with an approved MAP for EUDSI_U12 as required in SC III.2.² **(R 336.1910, R 336.1911, R 336.2803, R 336.2804)**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

NA

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall perform, and document non-certified visible emissions observations as required in SC I.1 on a daily basis when EUDSI_U12 is operating. If during the observation there are any visible emissions detected from an emission point, then corrective procedures as defined in the MAP shall be implemented. Records of the non-certified visible emissions observations, USEPA Method 9 observations that are performed, the reason for any visible emissions observed, and any corrective actions taken, shall be kept on file and in a format acceptable to the AQD.² **(R 336.1301(1)(c))**

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**
2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**
3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**
4. The permittee shall submit any performance test reports to the AQD Technical Programs Unit and District Office, in a format approved by the AQD. **(R 336.1213(3)(c), R 336.2001(5))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVLSS-BV1A	14 ²	140 ²	R 336.2803 R 336.2804
2. SVLSS-BV1B	14 ²	140 ²	R 336.2803 R 336.2804
3. SVLSS-BV1C	14 ²	140 ²	R 336.2803 R 336.2804
4. SVLSS-BV2A	14 ²	140 ²	R 336.2803 R 336.2804
5. SVLSS-BV2B	14 ²	140 ²	R 336.2803 R 336.2804
6. SVLSS-BV2C	14 ²	140 ²	R 336.2803 R 336.2804

IX. OTHER REQUIREMENT(S)

NA

Footnotes:

¹ This condition is state only enforceable and was established pursuant to Rule 201(1)(b).

² This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUACI_U123 EMISSION UNIT CONDITIONS

DESCRIPTION

Activated carbon (or other sorbent) material handling including four (4) silos for Boiler Units 1, 2, and 3.

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

Bin vent filters

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Opacity	5% ²	6- Minute Average	Each bin vent filter in EUACI_U123	SC VI.1	R 336.1301(1)(c)
2. PM	0.004 gr / dscf of exhaust gases ²	Hourly	Each bin vent filter in EUACI_U123	SC III.2 SC VI.1	R 336.1331(1)(c)
3. PM10	0.045 pph ²	Hourly	Each of the following bin vent filter emission points: SVACI-BV1A SVACI-BV2A	SC III.2 SC VI.1	R 336.2803 R 336.2804
4. PM2.5	0.045 pph ²	Hourly	Each of the following bin vent filter emission points: SVACI-BV1A SVACI-BV2A	SC III.2 SC VI.1	R 336.2803 R 336.2804
5. PM10	0.041 pph ²	Hourly	Each of the following bin vent filter emission points: SVACI-BV3A SVACI-BV3B	SC III.2 SC VI.1	R 336.2803 R 336.2804
6. PM2.5	0.041 pph ²	Hourly	Each of the following bin vent filter emission points: SVACI-BV3A SVACI-BV3B	SC III.2 SC VI.1	R 336.2803 R 336.2804

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The Campbell Complex fugitive dust plan shall be updated as necessary and kept at the facility. If at any time the fugitive dust control program fails to address or inadequately addresses a dusting event, the permittee shall amend the fugitive dust control program within 45 days after such an event occurs. The permittee shall also amend the fugitive dust control program within 45 days, if new equipment is installed or upon request from the

AQD District Supervisor. The permittee shall submit the fugitive dust control program and any amendments to the fugitive dust control program to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the fugitive dust control program or amended fugitive dust control program shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.² **(R 336.1372, R 336.2803, R 336.2804, Act 451, Section 324.5524)**

2. The permittee shall not operate EUACI_U123 unless a malfunction abatement plan (MAP) as described in Rule 911(2), for operation of the process and emission control equipment, is implemented updated as necessary, and kept at the facility. If at any time the MAP fails to address or inadequately addresses an event that meets the characteristics of a malfunction, the permittee shall amend the MAP within 45 days after such an event occurs. The permittee shall also amend the MAP within 45 days, if new equipment is installed or upon request from the AQD District Supervisor. The permittee shall submit the MAP and any amendments to the MAP to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the MAP or amended MAP shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.² **(R 336.1910, R 336.1911)**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall not operate any portion of EUACI_U123 unless the associated enclosures and bin vent filters are installed, maintained and operated in a satisfactory manner. Satisfactory manner includes operating and maintaining each control device in accordance with an approved MAP for EUACI_U123 as required in SC III.2.² **(R 336.1910, R 336.1911, R 336.2803, R 336.2804)**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

NA

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall perform, and document non-certified visible emissions observations as required in SC I.1 on a daily basis when EUACI_U123 is operating. If during the observation there are any visible emissions detected from an emission point, then corrective procedures as defined in the MAP shall be implemented. Records of the non-certified visible emissions observations, USEPA Method 9 observations that are performed, the reason for any visible emissions observed, and any corrective actions taken, shall be kept on file and in a format acceptable to the AQD.² **(R 336.1301(1)(c))**

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**
2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**
3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVACI-BV1A	14 ²	60 ²	R 336.2803 R 336.2804
2. SVACI-BV2A	14 ²	60 ²	R 336.2803 R 336.2804
3. SVACI-BV3A	12 ²	80 ²	R 336.2803 R 336.2804
4. SVACI-BV3B	12 ²	80 ²	R 336.2803 R 336.2804

IX. OTHER REQUIREMENT(S)

NA

Footnotes:

¹ This condition is state only enforceable and was established pursuant to Rule 201(1)(b).

² This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUBYPRODUCT EMISSION UNIT CONDITIONS

DESCRIPTION

Flyash and byproduct handling system that transports flyash and byproduct from the plant to the disposal silos. The Unit 3 Transfer Tanks A and B (SVTT-BV3A and SVTT-BV3B) as well as Landfill Silo's A, B, and C (SVDCASS-BVA, SVDCASS-BVB, and SVDCASS-BVC) are subject to 40 CFR Part 64 (CAM).

Unit 3 System

- A large portion of PJFF flyash/byproduct is recycled back to the SDA via the SDA Recycle Flyash System and the remainder is conveyed to the Unit 3 Dry Flyash Byproduct System (for resale or landfill). The SDA Byproduct System consists of the following major equipment: two transfer towers [TT3A and TT3B], three vacuum exhausters [two in operation and one spare], and three disposal silos [Flyash Silos A, B, and C]. Each transfer tower includes two filter separators (F/S) and a single transfer tank. Each transfer tank and each disposal silo are equipped with a bin vent filter. TT3A, TT3B and the three associated vacuum exhausters located at Boiler 3 are regulated under EUBYPRODUCT.
- The vacuum conveyance system pulls flyash from the PJFF hoppers and transports the flyash in hard piping through a F/S and into a transfer tank where the conveyance air is then discharged through a vacuum exhauster (two F/S's per transfer tank. Transfer tank displacement air is released through a bin vent filter to atmosphere. Flyash and byproduct materials collected in the transfer tanks are periodically conveyed to disposal silos A, B, or C where the material is loaded onto trucks for shipment as either byproduct or waste.

Unit 1 and 2 System

- The Dry Flyash Handling System services both Unit 1 and Unit 2 and consists of the following major equipment: three transfer towers [TT1, TT2 and TT3], five vacuum exhausters [three in operation and two spares], and two disposal silos [DSA, DSB]. Each transfer tower includes a filter separator and transfer tank. Each transfer tank and each disposal silo are equipped with a bin vent filter.
- TT1 and TT2 and the three associated vacuum exhausters located at Boiler 1&2 are regulated under EUBYPRODUCT. TT3 and the remaining two associated vacuum exhausters that solely support Unit 2 are not regulated by EUBYPRODUCT and are exempt from permitting under Michigan Rule 284(k).
- The vacuum conveyance system pulls flyash from each Boiler Unit's PJFF hoppers and transports the flyash in hard piping through a filter separator and into a transfer tank where the conveyance air is then discharged through a vacuum exhauster. The three vacuum exhausters that serve TT1 and TT2 normally discharge to the Unit 1 PJFF inlet ductwork. The two vacuum exhausters that serve TT3 can only discharge to the Unit 2 PJFF inlet duct. Transfer tank displacement air is released through a bin vent filter to atmosphere. Flyash and byproduct materials collected in the transfer tanks are periodically conveyed to disposal silos DSA and DSB where the material is loaded onto trucks for shipment as either byproduct or waste.
- When Boiler 1 and its associated PJFF are not in operation, then the vacuum exhausters associated with TT1 and TT2 will be redirected and one vacuum exhauster may intermittently discharge controlled emissions to atmosphere through a dedicated stack (bypassing the Boiler 1 PJFF). The operation of TT3 and its associated vacuum exhausters would remain unchanged; discharging into the Unit 2 inlet PJFF ductwork.

Common

- 3 Disposal Silos (A, B, & C) – located at the landfill, and store the byproduct/flyash until disposed in licensed landfill.
- Truck loading – each disposal silo has a loading bay under the silo where trucks are loaded with byproduct/flyash for transport to the landfill or for beneficial re-use. "B" silo also employs an exterior load-out chute.

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

Transfer tank: Each tank has as a filter separator that breaks the vacuum of the conveyance air to separate the transported material (the flyash byproduct) from the conveyance air. The filter separator is the fabric filter control for the conveyance air. The displacement air from the byproduct dropping into the tank is controlled by a bin vent filter.

Vacuum exhausters: Although the conveyance air from the vacuum exhausters are already controlled by the filter separator (with 0.004 gr/dscf PM emission guarantee), the normal vacuum exhauster discharge configuration is to the PJFF inlet breeching ducts (for either Unit 1, 2, or 3). There are limited times when the Unit 1 PJFF is offline for maintenance or other purposes, at which time the filter separator serving Unit 2 and/or in-plant dust systems will discharge to atmosphere through a vacuum exhauster. Emissions are still controlled via the filter separator (upgraded in PTI No. 18-15) and will be monitored through bag leak dust detectors and visible emission observations under this limited operating scenario.

Disposal Silos: The Disposal Silos A, B and C are controlled by bin vent filter dust collectors.

Truck Loading: Each disposal silo has a dust collector and/or dust suppressant system in the truck loading bay under the silos to control particulate matter during truck loading. The byproduct headed for landfill disposal is sufficiently wetted/conditioned through a pin-paddle mixer prior to loading and transport. The dry load-out chutes minimize fugitive emissions by proper seating of the telescopic chute to or over the truck hatch. Emissions during transfer activity are vacuumed to discharge back into the storage silo, which is controlled by the bin vent filters.

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period / Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Opacity	5% ²	6- Minute Average	Each of the following bin vent filter emission points: SVTT12-BV1 SVTT12-BV2 SVTT12-FSVE SVTT3-BV3A SVTT3-BV3B SVDCASS-BVA SVDCASS-BVB SVDCASS-BVC	SC VI.1 SC VI.2	R 336.1301(1)(c)
2. PM	0.004 gr / dscf of exhaust gases ²	Hourly	Each of the following bin vent filter emission points: SVTT12-BV1 SVTT12-BV2 SVTT3-BV3A SVTT3-BV3B SVDCASS-BVA SVDCASS-BVB SVDCASS-BVC	SC III.2 SC VI.2	R 336.1331(1)(c)
3. PM	0.004 gr / dscf of exhaust gases ²	Hourly	Byproduct transfer tank vacuum exhauster SVTT12-FSVE	SC III.2 SC VI.2	R 336.1331(1)(c)

Pollutant	Limit	Time Period / Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
4. PM10	0.03 pph ²	Hourly	Each of the following bin vent filter emission points: SVTT12-BV1 SVTT12-BV2	SC III.2 SC VI.2	R 336.2803 R 336.2804
5. PM2.5	0.03 pph ²	Hourly	Each of the following bin vent filter emission points: SVTT12-BV1 SVTT12-BV2	SC III.2 SC VI.2	R 336.2803 R 336.2804
6. PM10	0.05 pph ²	Hourly	Each of the following bin vent filter emission points: SVTT3-BV3A SVTT3-BV2B (CAM Subject)	SC III.2 SC VI.1 SC VI.2	R 336.2803 R 336.2804
7. PM2.5	0.05 pph ²	Hourly	Each of the following bin vent filter emission points: SVTT3-BV3A SVTT3-BV3B (CAM Subject)	SC III.2 SC VI.1 SC VI.2	R 336.2803 R 336.2804
8. PM10	0.55 pph ²	Hourly	Each of the following bin vent filter emission points: SVDCASS-BVA SVDCASS-BVB SVDCASS-BVC (CAM Subject)	SC III.2 SC VI.1 SC VI.2	R 336.2803 R 336.2804
9. PM2.5	0.55 pph ²	Hourly	Each of the following bin vent filter emission points: SVDCASS-BVA SVDCASS-BVB SVDCASS-BVC (CAM Subject)	SC III.2 SC VI.1 SC VI.2	R 336.2803 R 336.2804
10. PM10	0.10 pph ²	Hourly	Byproduct transfer tank vacuum exhauster: SVTT12-FSVE	SC III.2 SC VI.2	40 CFR 52.21(c) and (d)
11. PM2.5	0.10 pph ²	Hourly	Byproduct transfer tank vacuum exhauster: SVTT12-FSVE	SC III.2 SC VI.2	40 CFR 52.21(c) and (d)
12. PM	0.10 lbs per 1,000 lbs. exhaust gas	Hourly	Unit 2 dry flyash transfer tower – including the transfer tank, hoppers, and vacuum exhauster	SC III.2 SC VI.2	R 336.1331

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The Campbell Complex fugitive dust plan shall be updated as necessary and kept at the facility. If at any time the fugitive dust control program fails to address or inadequately addresses a dusting event, the permittee shall amend the fugitive dust control program within 45 days after such an event occurs. The permittee shall also amend the fugitive dust control program within 45 days, if new equipment is installed or upon request from the AQD District Supervisor. The permittee shall submit the fugitive dust control program and any amendments to the fugitive dust control program to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the fugitive dust control program or amended fugitive dust control program shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.² **(R 336.1372, R 336.2803, R 336.2804, Act 451, Section 324.5524)**
2. The permittee shall not operate EUBYPRODUCT unless a malfunction abatement plan (MAP) as described in Rule 911(2), for operation of the process and emission control equipment, is implemented updated as necessary, and kept at the facility. If at any time the MAP fails to address or inadequately addresses an event that meets the characteristics of a malfunction, the permittee shall amend the MAP within 45 days after such an event occurs. The permittee shall also amend the MAP within 45 days, if new equipment is installed or upon request from the AQD District Supervisor. The permittee shall submit the MAP and any amendments to the MAP to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the MAP or amended MAP shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.² **(R 336.1910, R 336.1911)**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall not operate any portion of EUBYPRODUCT unless the associated enclosures and bin vent filters and filter separators are installed, maintained and operated in a satisfactory manner. Satisfactory manner includes operating and maintaining each control device in accordance with an approved MAP for EUBYPRODUCT as required in SC III.2.² **(R 336.1910, R 336.1911, R 336.2803, R 336.2804)**
2. The permittee shall not operate each byproduct transfer tank vacuum exhaustor unless the associated filter separator exhaust gases discharge to an associated PJFF baghouse on either EUBOILER1, EUBOILER2, or EUBOILER3, except as allowed in SC IV.3.² **(R 336.1205, R 336.1331, R 336.2803, R 336.2804)**
3. The exhaust from the filter/separator associated with EUBOILER2 shall be routed back to the PJFF for EUBOILER1, except at times when the PJFF for EUBOILER1 is not operating.² **(R 336.1205, R 336.1331, 40 CFR 52.21(c) and (d))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

NA

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall perform, and document non-certified visible emissions observations on all exhausts to the atmosphere as required in SC I.1 on a daily basis when EUBYPRODUCT is operating. If during the observation there are any visible emissions detected from an emission point, then corrective procedures as defined in the MAP shall be implemented. Records of the non-certified visible emissions observations, USEPA Method 9

observations that are performed, the reason for any visible emissions observed, and any corrective actions taken, shall be kept on file and in a format acceptable to the AQD.² **(R 336.1301(1)(c))**

2. The permittee shall conduct and record non-certified visible emissions observations from the bin vent filters servicing the EUBOILER3 Transfer Tanks (SVTT-BV3A, SVTT-BV3B) and the Landfill Silos (SVDCASS-BVA, SVDCASS-BVB, and SVCASSS-BVC) once per day when operating, as the primary indicator of the proper functioning of each bin vent filter for EUBYPRODUCT. If visible emissions are observed, the permittee shall document the visible emissions, including duration, and continue to observe the source of the visible emissions until no visible emissions are observed. The permittee shall initiate corrective actions as quickly as possible upon the detection of visible emissions. If there is a break in the visible emissions observations, it will be assumed that visible emissions continue to occur during any break in observations. The appropriate range of visible emissions defining proper functioning of each bin vent filter is no visible emissions. **(40 CFR 64.6(c)(1)(i), (ii), and (iii))**
3. The permittee shall utilize visible emissions as the primary indicator of the proper functioning of each PM control device. The appropriate range of visible emissions defining proper functioning of the PM Control Device is no visible emissions.² **(R 336.1201(3), 40 CFR 64.6(c)(1)(i) and (ii))**
4. The permittee shall keep, in a satisfactory manner, all records necessary to show that the Campbell Complex fugitive dust plan required by SC III.1 is being implemented.² **(R 336.1372, R 336.2803, R 336.2804, Act 451, Section 324.5524)**
5. The permittee shall keep, in a satisfactory manner, all records necessary to show that the MAP required by SC III.2 is being implemented.² **(R 336.1910, R 336.1911)**
6. The permittee shall keep, in a satisfactory manner, visible emissions records for the times that the filter/separator associated with EUBOILER2 is routed to SVTT12-FSVE instead of the PJFF for EUBOILER1.² **(R 336.1205, R 336.1331, 40 CFR 52.21(c) and (d), R 336.1213(3))**
7. The permittee shall restore operation of the emission unit, control device, and associated pollutant capture system equipment to normal/compliant operation as quickly as possible in response to any noted exceedance or excursion. **(40 CFR 64.7(d))**
8. Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions or as specified by the MAP. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). **(40 CFR 64.7(d))**
9. Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. **(40 CFR 64.6(c)(3), 40 CFR 64.7(c))**
10. The permittee shall properly maintain the monitoring system, including keeping necessary parts for routine repair of the monitoring equipment. **(40 CFR 64.7(b))**
11. The permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan and any activities undertaken to implement a quality improvement plan, and

other information such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions. **(40 CFR 64.9(b)(1))**

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**
2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**
3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**
4. Each semiannual report of monitoring and deviations shall include summary information on the number, duration and cause of excursions and/or exceedances and the corrective actions taken. If there were no excursions and/or exceedances in the reporting period, then this report shall include a statement that there were no excursions and/or exceedances. **(40 CFR 64.9(a)(2)(i))**
5. Each semiannual report shall include a Quality Improvement Plan (QIP) during the reporting period, if appropriate. If a QIP has been completed, the report shall include documentation that the QIP has been implemented, and a discussion pertaining to whether the QIP implementation has reduced the likelihood of excursions or exceedances. **(40 CFR 64.9(a)(2)(iii))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack and Vent ID	Maximum Exhaust Diameter/Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVTT12-BV1	9 ²	32 ²	R 336.2803 R 336.2804
2. SVTT12-BV2	9 ²	32 ²	R 336.2803 R 336.2804
3. SVTT12-FSVE	20 ²	40 ²	R 336.2803 R 336.2804
4. SVTT3-BV3A	14 ²	70 ²	R 336.2803 R 336.2804
5. SVTT3-BV3B	14 ²	70 ²	R 336.2803 R 336.2804
6. SVDCASS-BVA	24x60 ²	141 ²	R 336.2803 R 336.2804
7. SVDCASS-BVB	24x60 ²	141 ²	R 336.2803 R 336.2804
8. SVDCASS-BVC	24x60 ²	136 ²	R 336.2803 R 336.2804
9. SVBLR12	228 ²	400 ²	R 336.2803 R 336.2804
10. SVBLR3	327 ²	642 ²	R 336.2803 R 336.2804

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with all applicable requirements of 40 CFR Part 64. **(40 CFR Part 64)**
2. If the permittee identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the permittee shall promptly notify the AQD and if necessary, submit a proposed modification of the ROP and CAM Plan to address the necessary monitoring changes. Such a modification may include but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters. **(40 CFR 64.7(e))**

Footnotes:

¹ This condition is state only enforceable and was established pursuant to Rule 201(1)(b).

² This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUAUXBLR12 EMISSION UNIT CONDITIONS

DESCRIPTION

The common auxiliary boiler for Units 1 and 2 is an oil-fired fire-tube boiler rated at 17 MMBTU/hr. This boiler is a limited use boiler, which is defined in 40 CFR 63.7575 as any boiler that burns any amount of solid, liquid, or gaseous fuels and has a federally enforceable average annual capacity factor of no more than 10%. This unit is subject to the provisions of 40 CFR Part 63, Subpart DDDDD.

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

NA

II. MATERIAL LIMIT(S)

Material	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Fuel Oil	0.5% sulfur by weight based on a higher heating value of 18,000 BTU/lb ²	Applicable at all times	EUAUXBLR12	SC VI.1	R 336.1401(1), Table 41
2. #2 Fuel Oil (Note A)	10% annual capacity factor of oil (Note B) ²	Calendar Year	EUAUXBLR12	SC VI.4	40 CFR 63.7555(a)(3)

Note A: This limit is to satisfy the Federally Enforceable capacity factor limit associated with the limited use definition under 40 CFR Part 63, Subpart DDDDD, 40 CFR 63.7575.

Note B: Annual capacity factor means the ratio between the actual heat input to a boiler from the fuels burned during a calendar year to the potential heat input to the boiler had it been operated for 8,760 hours during a year at the maximum steady state design heat input capacity. (40 CFR 63.7575)

- The permittee shall only burn fuels as allowed in the Unit designed to burn gas under light liquid subcategory definition in 40 CFR 63.7575. **(40 CFR 63.7575, R336.1213(3))**

III. PROCESS/OPERATIONAL RESTRICTION(S)

- To demonstrate continuous compliance, the permittee shall conduct a tune-up of the boiler every 5 years (within 61 months) of the date of the last tune up. If the boiler is not operating on the required date for tune-up, the tune-up must be conducted within 30 calendar days of startup.² **(40 CFR 63.7500(a), 40 CFR 63.7515(d), 40 CFR 63.7540(12) and (13))**
- The permittee shall conduct tune up of the boiler as specified in the following:² **(40 CFR 63.7540(a)(12))**
 - As applicable, inspect the burner, and clean or replace any components of the burner as necessary (the permittee may delay the burner inspection until the next unit shutdown).
 - Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern.

- c. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (the permittee may delay the inspection until the next unit shutdown).
 - d. Optimize total emissions of CO.
 - e. Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made.
 - f. Maintain on-site and submit, if requested by the Administrator, a report containing the information below:
 - i. The concentrations of CO in the effluent stream in parts per million by volume, and oxygen content in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater.
 - ii. A description of any corrective actions taken as part of the tune-up.
3. At all times, the permittee must operate and maintain any affected source (as defined in 40 CFR 63.7490, stated in SC IX.1), including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. **(40 CFR 63.700(a)(3))**
4. Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in 40 CFR 63.7540. They are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, the annual tune-up, or the energy assessment requirements in Table 3 to this subpart, or the operating limits in Table 4 to this subpart. **(40 CFR 63.7500(c))**
5. The permittee shall install a fuel meter.² **(R 336.1201(3))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

NA

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

NA

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

- 1. The permittee shall maintain sufficient records to demonstrate that the sulfur content for each shipment of fuel oil received is less than 0.5% by weight.² **(R 336.1201(3))**
- 2. The permittee shall conduct and maintain records of a daily (non-certified) visual observation for opacity in order to verify proper firing, whenever a boiler is in use for 24 consecutive hours or more. **(R 336.1213(3))**
- 3. The permittee shall keep a record of the following on a monthly basis:² **(R 336.1201(3))**
 - a. Total fuel usage
 - b. Sulfur content of fuel oil
 - c. Higher Heating Value of fuel oil
- 4. The permittee shall keep fuel use records for the days the boiler was operating.² **(40 CFR 63.7525(k))**
- 5. The permittee shall maintain a complete record of fuel oil specifications and/or fuel analysis for each delivery, or storage tank, of fuel oil used for the auxiliary boiler. These records may include purchase records for ASTM specification fuel oil, specifications or analyses provided by the vendor at the time of delivery, analytical results from laboratory testing, or any other records adequate to demonstrate compliance with the percent sulfur limit in fuel oil.² **(R 336.1201(3))**

6. The permittee shall keep records of compliance demonstrations.² **(R°336.1201(3))**
7. For each unit that meets the definition of limited-use boiler or process heater, the permittee must keep fuel use records for the days the boiler or process heater was operating. **(40 CFR 63.7525(k))**
8. The permittee must keep records according to paragraphs (a)(1) and (2) of 40 CFR 63.7555. **(40 CFR 63.7555(a))**
 - a. A copy of each notification and report that is submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that permittee submitted, according to the requirements in 40 CFR Part 63.10(b)(2)(xiv). **(40 CFR 63.7555(a)(1))**
 - b. Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in 40 CFR Part 63.10(b)(2)(viii). **(40 CFR 63.7555(a)(2))**
9. For units in the limited use subcategory, the permittee must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the boiler or process heater was operating. **(40 CFR 63.7555(a)(3))**
10. Records must be in a form suitable and readily available for expeditious review, according to 40 CFR 63.10(b)(1). **(40 CFR 63.7560(a))**
11. As specified in 40 CFR 63.10(b)(1), the permittee must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. **(40 CFR 63.7560(b))**
12. The permittee must keep each record on site, or they must be accessible from on-site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 40 CFR 63.10(b)(1). The permittee can keep the records off site for the remaining 3 years. **(40 CFR 63.7560(c))**

See Appendix 3-C (Fuel Oil Sulfur Monitoring)

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**
2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**
3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**
4. The permittee must meet the notification requirements in 40 CFR 63.7545 according to the schedule in 40 CFR 63.7545 and in Subpart A of 40 CFR Part 63. **(40 CFR 63.7495(d))**
5. The permittee must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in 40 CFR 63.7545(e). **(40 CFR 63.7530(f))**
6. The permittee must submit to the Administrator all of the notifications in 40 CFR 63.7(b) and (c); 40 CFR 63.8(e), (f)(4) and (6); and 40 CFR 63.9(b) through (h) that apply by the dates specified. **(40 CFR 63.7545(a))**
7. Unless the USEPA Administrator has approved a different schedule for submission of reports under 40 CFR Part 63.10(a), the permittee must submit each report, according to paragraph (h) of 40 CFR 63.7550, by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (4) of 40 CFR 63.7550 as stated below. **(40 CFR 63.7550(b))**

- a. Each semi-annual compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31. **(40 CFR 63.7550(b)(3))**
 - b. Each semi-annual compliance report must be postmarked or submitted no later than September 15 or March 15, whichever date is the first date following the end of the semiannual reporting period. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than March 15. **(40 CFR 63.7550(b)(4), 40 CFR 63.7550(b)(5))**
8. A compliance report must contain the information below depending on how the facility chooses to comply with the limits set in this rule. **(40 CFR 63.7550(c))**
- a. If the facility is subject to the requirements of a tune-up, permittee must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii), (xiv) and (xvii) of 40 CFR 63.7550, and paragraph (c)(5)(iv) of 40 CFR 63.7550 for limited-use boiler or process heater. **(40 CFR 63.7550(c)(1))**
 - b. 40 CFR 63.7550(c)(5) is as follows:
 - i. Company and Facility name and address. **(40 CFR 63.7550(c)(5)(i))**
 - ii. Process unit information, emissions limitations, and operating parameter limitations. **(40 CFR 63.7550(c)(5)(ii))**
 - iii. Date of report and beginning and ending dates of the reporting period. **(40 CFR 63.7550(c)(5)(iii))**
 - iv. The total operating time during the reporting period. **(40 CFR 63.7550(c)(5)(iv))**
 - v. Include the date of the most recent tune-up for each unit subject to only the requirement to conduct a 5-year tune-up according to 40 CFR 63.7540(a)(12). Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown. **(40 CFR 63.7550(c)(5)(xiv))**
 - vi. Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report. **(40 CFR 63.7550(c)(5)(xvii))**
9. The permittee must submit all reports required by Table 9 of 40 CFR Part 63, Subpart DDDDD electronically to the USEPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the USEPA's CDX.) The permittee must use the appropriate electronic report in CEDRI for 40 CFR Part 63, Subpart DDDDD. Instead of using the electronic report in CEDRI for 40 CFR Part 63, Subpart DDDDD, the permittee may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (<http://www.epa.gov/ttn/chief/cedri/index.html>), once the XML schema is available. If the reporting form specific to 40 CFR Part 63, Subpart DDDDD is not available in CEDRI at the time that the report is due, the permittee must submit the report to the Administrator at the appropriate address listed in 40 CFR 63.13. The permittee must begin submitting reports via CEDRI no later than 90-days after the form becomes available in CEDRI. **(40 CFR 63.7550(h)(3))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVAUXBLR12	30 ²	153 ²	NA

IX. OTHER REQUIREMENT(S)

1. 40 CFR Part 63, Subpart DDDDD applies to new or reconstructed affected sources as described in paragraph (a)(2) of 40 CFR 63.7490, as listed below. **(40 CFR 63.7490(a))**
 - a. The affected source of 40 CFR Part 63, Subpart DDDDD is each new or reconstructed industrial, commercial, or institutional boiler or process heater, as defined in 40 CFR 63.7575, located at a major source. **(40 CFR 63.7490(a)(2))**
2. A boiler or process heater is:
 - a. New if the permittee commences construction of the boiler or process heater after June 4, 2010, and the permittee meets the applicability criteria at the time the permittee commences construction. **(40 CFR 63.7490(b))**
 - b. Reconstructed if the permittee meets the reconstruction criteria as defined in 40 CFR 63.2, the permittee commences reconstruction after June 4, 2010, and the permittee meets the applicability criteria at the time the permittee commence reconstruction. **(40 CFR 63.7490(c))**
3. For affected sources (as defined in 40 CFR 63.7490) that have not operated since the previous compliance demonstration and more than one year has passed since the previous compliance demonstration, you must complete the subsequent compliance demonstration no later than 180 days after the re-start of the affected source and according to the applicable provisions in 40 CFR 63.7(a)(2) as cited in Table 10 to 40 CFR Part 63, Subpart DDDDD. You must complete a subsequent tune-up by following the procedures described in 40 CFR 63.7540(a)(10)(i) through (vi) and within 30 calendar days of startup for units that are not operating at the time of their scheduled tune-up. **(40 CFR 63.7515(g))**
4. The permittee shall comply with the General Provisions in 40 CFR 63.1 through 63.15 that apply to this source as indicated in Table 10 of 40 CFR Part 63, Subpart DDDDD. **(40 CFR 63.7565, Table 10)**
5. The permittee shall comply with the applicable requirements of 40 CFR Part 63, Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. **(40 CFR Part 63, Subpart DDDDD)**

Footnotes:

¹ This condition is state only enforceable and was established pursuant to Rule 201(1)(b).

² This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUCAT3DIESEL EMISSION UNIT CONDITIONS

DESCRIPTION

On-site, stationary, diesel-fired internal combustion engine, 9.4 MMBTU/hr heat input; emergency use only. This unit is subject to the provisions of 40 CFR Part 63, Subpart ZZZZ.

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

NA

II. MATERIAL LIMIT(S)

Material	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Fuel Oil – sulfur content	1.0% by weight at 18,000 BTU/lb	Instantaneous; at all times	EUCAT3DIESEL	SC VI.6 (Use of No. 2 Fuel Oil, which by definition contains <0.5% Sulfur by weight; see Appendix 3-C-1)	R 336.1401(1), Table 41

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall:
 - a. Change oil and filter every 500 hours of operation or annually, whichever comes first, except as allowed in SC III.2;
 - b. Inspect the air filter every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and
 - c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

If the emergency engine is being operated during an emergency and it is not possible to shut down the engine to perform the work practice standards on the schedule required, the work practice standard can be delayed until the emergency is over. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State or local law has been abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, State or local law or which the risk was deemed unacceptable. **(40 CFR 63.6602, 40 CFR Part 63, Subpart ZZZZ, Table 2c, Item 1)**

2. The permittee may utilize an oil analysis program in order to extend the specified oil change requirement. The oil analysis must be performed at the same frequency as oil changes are required. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c of 40 CFR Part 63, Subpart ZZZZ. **(40 CFR 63.6625(i))**
3. The permittee shall install, maintain and operate EUCAT3DIESEL and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions. **(40 CFR 63.6605, 40 CFR 63.6625(e))**
4. The permittee shall minimize the time spent at idle during startup and minimize the startup time EUCAT3DIESEL to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup apply. **(40 CFR 63.6625(h))**
5. There is no time limit on the use of emergency stationary RICE in emergency situations. **(40 CFR 63.6640(f)(1))**
6. The permittee may operate EUCAT3DIESEL for no more than 100 hours per calendar year for the purpose of necessary maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The permittee may petition the Department for approval of additional hours to be used for maintenance checks and readiness testing. A petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency internal combustion engines beyond 100 hours per calendar year. **(40 CFR 63.6640(f)(2))**
7. EUCAT3DIESEL may operate up to 50 hours per calendar year in non-emergency situations, but those 50 hours are counted towards the 100 hours per calendar year provided for maintenance and testing as provided in 40 CFR 63.6640(f)(2). The 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for the permittee to supply non-emergency power as part of a financial arrangement with another entity. **(40 CFR 63.6640(f)(3))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall install a non-resettable hour meter on each engine in EUCAT3DIESEL. **(40 CFR 63.6625(f))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. If using the oil analysis program, the permittee must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30% of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20% from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine. **(40 CFR 63.6625(i))**

See Appendix 3-C

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall keep in a satisfactory manner, records of the occurrence and duration of each malfunction of operation or the air pollution control monitoring equipment. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 63.6655(a)(2), 40 CFR 63.6660)**
2. The permittee shall keep in a satisfactory manner, records of actions taken during periods of malfunction to minimize emissions, including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 63.6655(a)(5), 40 CFR 63.6660)**
3. The permittee shall keep in a satisfactory manner, records to demonstrate continuous compliance with the operating limitations. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 63.6655(d), 40 CFR 63.6660)**
4. The permittee shall keep in a satisfactory manner, records of the maintenance conducted to demonstrate that the engine and after-treatment control device (if any) were operated and maintained according to the developed maintenance plan. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 63.6655(e), 40 CFR 63.6660)**
5. The permittee shall monitor and record the total hours of operation for EUCAT3DIESEL per calendar year, recorded through the non-resettable hours meter, in a manner acceptable to the AQD District Supervisor. The permittee shall document how many hours are spent for emergency operation; including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purposes specified in 40 CFR 63.6640(f)(4)(ii), the permittee must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation. **(40 CFR 63.6655(f))**
6. The permittee shall maintain sufficient records to demonstrate that the sulfur content for each shipment of fuel oil received is less than 1.0% by weight. **(R 336.1213(3))**
7. The permittee shall conduct and maintain records of a daily (non-certified) visual observation for opacity in order to verify proper firing, whenever an engine is in use for 24 consecutive hours or more. **(R 336.1213(3))**
8. The permittee shall maintain a record of the applicability determination for each Reciprocating Internal Combustion Engine (RICE) relative to the requirements of 40 CFR Part 63, Subparts A and ZZZZ. **(40 CFR Part 63, Subpart A, Section 63.10(b)(3))**

See Appendix 3-C (Fuel Oil Sulfur Monitoring)

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**
2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**
3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. The permittee shall submit to the AQD District Supervisor, a semiannual compliance report, as specified in 40 CFR 63.6650, which contains all deviations during the reporting period from any applicable emission limitation or operating limitation. If there are no deviations from any applicable emission limitations or operating limitations, the report shall contain a statement that there were no deviations during the reporting period. The first report shall cover the period beginning on the applicable compliance date specified in 40 CFR 63.6595 and ending on June 30 (postmarked or delivered by July 31) or December 31 (postmarked or delivered by January 31), whichever date is the first date following the end of the first calendar half after the applicable compliance date. Each subsequent report must cover the semiannual period from January 1 through June 30, or from July 1 through December 31. The subsequent reports must be postmarked or delivered by July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period, except as allowed in 40 CFR 63.6650(b)(5). The compliance report must also contain the following information, as specified in 40 CFR 63.6650(c) and (d):
 - a. Company name and address.
 - b. Certification of the report by a responsible official.
 - c. Date of report and beginning and ending dates of the reporting period.
 - d. The number of malfunctions, including a brief description of each event, that occurred during the reporting period and a demonstration that the Malfunction Plan was followed during such events.
 - e. The total operating time of the RICE at which the deviation occurred during the reporting period.
 - f. The number, duration, and cause of deviations and the corrective action taken.

A copy of the compliance report shall be kept on file for a period of at least five years (at least two years at the site) and made available to the Department upon request. **(40 CFR 63.6640(b), 40 CFR 63.6650(b),(c),(d), 40 CFR 63.6660)**

5. Each affected source that has obtained a Title V operating permit pursuant to 40 CFR Part 70 or 71 must report all deviations as defined in 40 CFR Part 63, Subpart ZZZZ in the semiannual monitoring report required by 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to Table 7 of 40 CFR Part 63, Subpart ZZZZ along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in 40 CFR Part 63, Subpart ZZZZ, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority. **(40 CFR 63.6650(f))**
6. For any engine that is an emergency stationary engine with a site rating of more than 100 brake hp that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in 40 CFR 63.6640(f)(4)(ii), you must submit an annual report according to the requirements below and as specified in 40 CFR 63.6650(h): **(40 CFR 63.6650(h), 40 CFR 63.6660)**
 - a. The report must contain the following information:
 - i. Company name and address where the engine is located.
 - ii. Date of the report and beginning and ending dates of the reporting period.
 - iii. Engine site rating and model year.
 - iv. Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.
 - v. Hours operated for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii).
 - vi. Number of hours the engine is contractually obligated to be available for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii).

- vii. Hours spent for operation for the purpose specified in 40 CFR 63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in 40 CFR 63.6640(f)(4)(ii). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.
 - viii. If there were no deviations from the fuel requirements in 40 CFR 63.6604 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.
 - ix. If there were deviations from the fuel requirements in 40 CFR 63.6604 that apply to the engine (if any), information on the number, duration, and cause of deviations, and the corrective action taken.
- b. The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through USEPA's Central Data Exchange (CDX) (www.epa.gov/cdx). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in 40 CFR 63.13.

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the provisions of the National Emission Standards for Hazardous Air Pollutants, as specified in 40 CFR Part 63, Subparts A and ZZZZ, as they apply to EUCAT3DIESEL. **(40 CFR Part 63, Subparts A and ZZZZ)**

Footnotes:

¹ This condition is state only enforceable and was established pursuant to Rule 201(1)(b).

² This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUCATDIESEL12 EMISSION UNIT CONDITIONS

DESCRIPTION

A 2,000-kilowatt (kW) diesel-fueled emergency engine manufactured in 2007 or later. This unit is subject to the provisions of 40 CFR Part 60, Subpart IIII and 40 CFR Part 63, Subpart ZZZZ.

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period / Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. NMHC + NO _x	6.4 g/kW-hr ²	Hourly	EUCATDIESEL12	SC V.1 SC VI.2	40 CFR 60.4205(b)
2. CO	3.5 g/kW-hr ²	Hourly	EUCATDIESEL12	SC V.1 SC VI.2	40 CFR 60.4205(b)
3. PM	0.20 g/kW-hr ²	Hourly	EUCATDIESEL12	SC V.1 SC VI.2	40 CFR 60.4205(b)

II. MATERIAL LIMIT(S)

1. The permittee shall burn only diesel fuel, in EUCATDIESEL12, with a sulfur content not to exceed 15 ppm (0.0015%) by weight.² (**R 336.1205(3), R 336.1402(1), 40 CFR 60.4207, 40 CFR 80.510(b)**)

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall not operate EUCATDIESEL12 for more than 500 hours per year on a 12-month rolling time period basis as determined at the end of each calendar month. The 500 hours includes the 100 hours for the purpose of necessary maintenance checks and readiness testing as described in SC III.2.² (**R 336.1205(3), R 336.1225, R 336.1702(a), R 336.2803, R 336.2804, 40 CFR 52.21(c) & (d)**)
2. The permittee may operate EUCATDIESEL12 for no more than 100 hours per calendar year, as determined at the end of each calendar month, for the purpose of necessary maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. The permittee may petition the Department for approval of additional hours to be used for maintenance checks and readiness testing. A petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency internal combustion engines beyond 100 hours per calendar year. EUCATDIESEL12 may operate up to 50 hours per calendar year in non-emergency situations, but those 50 hours are counted towards the 100 hours per calendar year provided for maintenance and testing. The 50 hours per calendar year for non-emergency situations may not be used for peak shaving or to generate income for a facility to supply non-emergency power as part of a financial arrangement with another entity.² (**40 CFR 60.4211(f), 40 CFR 63.6640(f)**)

3. The permittee shall install, maintain, and operate EUCATDIESEL12 according to the manufacturer emissions-related written instructions, or procedures developed by the owner/operator and approved by the engine manufacturer, over the entire life of the engine.² **(R 336.1205(3), R 336.1225, R 336.1911, R 336.2803, R 336.2804, 40 CFR 52.21(c) & (d), 40 CFR 60.4206, 40 CFR 60.4211)**
4. There is no time limit on the use of emergency stationary RICE in emergency situations. **(40 CFR 60.4211(f)(1), 40 CFR 63.6640(f)(1))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall equip and maintain EUCATDIESEL12 with a non-resettable hours meter to track the operating hours.² **(R 336.1205(3), R 336.1225, 40 CFR 60.4209(a), 40 CFR 63.6625(f))**
2. The nameplate capacity of EUCATDIESEL12 shall not exceed 2,000 kW, as certified by the equipment manufacturer.² **(R 336.1205(3))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall conduct an initial performance test for EUCATDIESEL12 within one year after startup of the engine to demonstrate compliance with the emission limits in 40 CFR 60.4205 unless the engine has been certified by the manufacturer and the permittee maintains the engine as required by 40 CFR Part 60, Subpart IIII. If a performance test is required, the performance tests shall be conducted at the owner's expense, in accordance with Department requirements and according to 40 CFR 60.4212. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. The permittee must submit a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test.² **(40 CFR 60.4211)**
2. The permittee shall notify the AQD Technical Programs Unit Supervisor and the District Supervisor not less than 7 days of the time and place before performance tests are conducted. **(R 336.1213(3))**

See Appendix 5

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall complete all required calculations in a format acceptable to the AQD District Supervisor by the last day of the calendar month, for the previous calendar month, unless otherwise specified in any monitoring/recordkeeping special condition.² **(R 336.1205(3), R 336.2803, R 336.2804, 40 CFR 52.21 (c) & (d))**
2. The permittee shall keep, in a satisfactory manner, a record of testing required in SC V.1 or manufacturer certification documentation indicating that EUCATDIESEL12 meets the applicable emission limitations contained in the federal Standards of Performance for New Stationary Sources 40 CFR Part 60, Subpart IIII. The permittee shall keep all records on file and make them available to the Department upon request.² **(40 CFR 60.4211)**
3. The permittee shall monitor and record the total hours of operation and the hours of operation during non-emergencies for EUCATDIESEL12, on a monthly and 12-month rolling time period basis, in a manner acceptable to the AQD District Supervisor. The permittee shall document how many hours are spent for emergency operation of EUCATDIESEL12, including what classified the operation as emergency and how many hours are spent for maintenance or readiness testing and non-emergency operation.² **(R 336.1205(3), R 336.2803, R 336.2804, 40 CFR 60.4211(f), 40 CFR 60.4214(b))**

4. The permittee shall keep, in a satisfactory manner, fuel supplier certification records or fuel sample test data, for each delivery of diesel fuel oil used in EUCATDIESEL12, demonstrating that the fuel sulfur content meets the requirement of 40 CFR 80.510(b). The certification or test data shall include the name of the oil supplier or laboratory, and the sulfur content of the fuel oil.² **(R 336.1205(3), R 336.1402(1), 40 CFR 80.510(b))**

See Appendix 3-C

VII. REPORTING

1. The permittee shall submit all applicable notifications specified in 40 CFR 63.7(b) and (c), 40 CFR 63.8 (e), (f)(4), and (f)(6), and 40 CFR 63.9(b) through (e), (g), and (h) by the dates specified.² **(40 CFR 63.6645(a)(3) and (f))**
2. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**
3. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**
4. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**
5. The permittee shall submit any performance test reports to the AQD Technical Programs Unit and District Office, in a format approved by the AQD. **(R 336.1213(3)(c), R 336.2001(5))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Diameter/ Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVCATDIESEL12	18 ^{2*}	47 ²	R 336.1225 R 336.2803 R 336.2804 40 CFR 52.21 (c) & (d)

* The maximum diameter applies to the exhaust stack itself and does not apply to any no-loss rain sleeve that may be in use.

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the provisions of the federal Standards of Performance for New Stationary Sources as specified in 40 CFR Part 60, Subparts A and IIII, as they apply to EUCATDIESEL12.² **(40 CFR Part 60, Subparts A & IIII,)**
2. The permittee shall comply with the provisions of the National Emission Standards for Hazardous Air Pollutants, as specified in 40 CFR Part 63, Subparts A and ZZZZ, as they apply to EUCATDIESEL12 upon startup.² **(40 CFR Part 63, Subparts A and ZZZZ, 40 CFR 63.6595)**

Footnotes:

¹ This condition is state only enforceable and was established pursuant to Rule 201(1)(b).

² This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUGUARDSHK_ENG EMISSION UNIT CONDITIONS

DESCRIPTION

A natural-gas, stationary internal combustion engine rated at 40 HP; Emergency Generator for the guard shack. This unit is subject to the provisions of 40 CFR Part 60, Subpart JJJJ and 40 CFR Part 63, Subpart ZZZZ.

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. NO _x + Hc	10 g/kW-hr g/hp-hr	Hourly	EUGUARDSHK_ENG	SC VI.2	40 CFR 60.6233(d)
2. CO	387 g/hp-hr	Hourly	EUGUARDSHK_ENG	SC VI.2	40 CFR 60.6233(d)

II. MATERIAL LIMIT(S)

- The permittee shall burn only field or pipeline quality natural gas, in each engine in EUGUARDSHK_ENG. **(40 CFR 60.4230, R 336.1213(3))**

III. PROCESS/OPERATIONAL RESTRICTION(S)

- There is no time limit on the use of emergency stationary RICE in emergency situations. **(40 CFR 60.4243(d)(1))**
- The permittee may operate EUGUARDSHK_ENG for no more than 100 hours per calendar year for the purpose of necessary maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The permittee may petition the Department for approval of additional hours to be used for maintenance checks and readiness testing. A petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency internal combustion engines beyond 100 hours per calendar year. **(40 CFR 60.4243(d)(2), 40 CFR 63.6640(f))**
- EUGUARDSHK_ENG may operate up to 50 hours per calendar year in non-emergency situations, but those 50 hours are counted towards the 100 hours per calendar year provided for maintenance and testing as provided in 40 CFR 60.4243(d)(2). The 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for the permittee to supply non-emergency power as part of a financial arrangement with another entity. **(40 CFR 60.4243(d)(3), 40 CFR 63.6640(f))**
- The permittee shall operate and maintain EUGUARDSHK_ENG such that it meets the emission limits in SC I.1, and I.2 over the entire life of the engine. **(40 CFR 60.4234, 40 CFR 60.4243(b))**
- If the permittee purchased a certified engine, according to procedures specified in 40 CFR Part 60, Subpart JJJJ, for the same model year, the permittee shall meet the following requirements for EUGUARDSHK_ENG:
 - Operate and maintain the certified engine and control device according to the manufacturer's emission-related written instructions;

- b. Keep a maintenance plan and the permittee may only change those engine settings that are permitted by the manufacturer. If you do not operate and maintain the certified engine and control device according to the manufacturer's emission-related written instructions, the engine will be considered a non-certified engine; and
- c. Meet the requirements as specified in 40 CFR Part 1068, Subparts A through D.

If the permittee does not operate and maintain the certified engine and control device according to the manufacturer's emission-related written instructions, the engine will be considered a non-certified engine and be subject to SC III.5. **(40 CFR 60.4243(b)(1))**

- 6. If the permittee purchased a non-certified engine or a certified engine operating in a non-certified manner, the permittee shall keep a maintenance plan for EUGUARDSHK_ENG and shall, to the extent practicable, maintain and operate each engine in a manner consistent with good air pollution control practice for minimizing emissions. **(40 CFR 60.4243(b)(2))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

- 1. EUGUARDSHK_ENG shall be certified to meet the applicable emission standard of 40 CFR 60.4233. The permittee shall install and configure each engine according to the manufacturer's specifications. **(40 CFR 60.4243)**
- 2. The permittee shall equip and maintain EUGUARDSHK_ENG with non-resettable hours meters to track the operating hours. **(40 CFR 60.4237, 40 CFR 63.6655(f))**
- 3. The nameplate capacity of EUGUARDSHK_ENG shall not exceed 500 BHP, as certified by the equipment manufacturer. **(40 CFR 63.6590(c)(4))**

V. TESTING/SAMPLING

- 1. The permittee shall conduct an initial performance test for EUGUARDSHK_ENG within one year after startup of the engine to demonstrate compliance with the emission limits in 40 CFR 60.4231 unless the engine has been certified by the manufacturer and the permittee maintains the engine as required by 40 CFR Part 60, Subpart JJJJ. If a performance test is required, the performance test shall be conducted at the owner's expense, in accordance with Department requirements and according to 40 CFR 60.4244. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. The permittee must submit a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test.² **(40 CFR 60.4244)**
- 2. The permittee shall notify the AQD Technical Programs Unit Supervisor and the District Supervisor not less than 7 days of the time and place before performance tests are conducted. **(R 336.1213(3))**

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

- 1. The permittee shall keep in a satisfactory manner, records of all maintenance conducted on EUGUARDSHK_ENG. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 60.4245(a)(2))**
- 2. The permittee shall keep, in a satisfactory manner, a record of testing required in SC V.1 or manufacturer certification documentation indicating that EUGUARDSHK_ENG meets the applicable emission limitations contained in the federal Standards of Performance for New Stationary Sources 40 CFR Part 60, Subpart JJJJ. The permittee shall keep all records on file and make them available to the Department upon request. **(40 CFR 60.4245)**

3. The permittee shall monitor and record the hours of operation of EUGUARDSHK_ENG during emergencies and non-emergencies, on a calendar year basis, in a manner acceptable to the AQD District Supervisor. The permittee shall record the time of operation of EUGUARDSHK_ENG and the reason it was in operation during that time. **(40 CFR 60.4243)**

See Appendix 4

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**
2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**
3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the provisions of the federal Standards of Performance for New Stationary Sources as specified in 40 CFR Part 60, Subparts A and JJJJ, as they apply to EUGUARDSHK_ENG. **(40 CFR Part 60, Subparts A and JJJJ)**
2. The permittee shall comply with all applicable provisions of the National Emission Standards for Hazardous Air Pollutants, as specified in 40 CFR Part 63, Subparts A and ZZZZ, for Stationary Reciprocating Internal Combustion Engines by the initial compliance date. **(40 CFR 63.6595, 40 CFR Part 63, Subparts A and ZZZZ)**

Footnotes:

¹ This condition is state only enforceable and was established pursuant to Rule 201(1)(b).

² This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

D. FLEXIBLE GROUP SPECIAL CONDITIONS

Part D outlines the terms and conditions that apply to more than one emission unit. The permittee is subject to the special conditions for each flexible group in addition to the General Conditions in Part A and any other terms and conditions contained in this ROP.

The permittee shall comply with all specific details in the special conditions and the underlying applicable requirements cited. If a specific condition type does not apply, NA (not applicable) has been used in the table. If there are no special conditions that apply to more than one emission unit, this section will be left blank.

FLEXIBLE GROUP SUMMARY TABLE

The descriptions provided below are for informational purposes and do not constitute enforceable conditions.

Flexible Group ID	Flexible Group Description	Associated Emission Unit IDs
FGBOILER12	The common 40 CFR Part 64 (CAM) requirements for these emission units are in this flexible group.	EUBOILER1 EUBOILER2
FGMATS_U12	Common applicable Mercury and Air Toxics Standard requirements for EUBOILER1 and EUBOILER2.	EUBOILER1 EUBOILER2
FGMATS_U3	Mercury and Air Toxics Standard requirements for EUBOILER3.	EUBOILER3
FGEXISTINGRICE	Onsite, stationary diesel-fired internal combustion engines. Engines used as a source of emergency power or water supply that are subject to the RICE MACT.	EUCATFIREPUMP3 EUHPHSWP15001 EUHPHSWP15002 EUHPHSWP3000
FGAUXBLRS3	Distillate oil fired auxiliary boilers less than 10 MMBTU.	EUAUXBLR3B EUAUXBLR3C
FGNEWCIRICE	New stationary diesel-fired internal combustion, compression ignition engines. Engines used as a source of emergency power or water supply that are subject to the RICE MACT.	EUWPDIESEL EUTRNCNTRDIESEL
FGPARTSCLEANERS	Any cold cleaner that is grandfathered or exempt from Rule 201 pursuant to Rule 278, 278a and Rule 281(2)(h) or Rule 285(2)(r)(iv). Existing cold cleaners were placed into operation prior to July 1, 1979. New cold cleaners were placed into operation on or after July 1, 1979.	EUPARTSCLEANERS

FGBOILER12 FLEXIBLE GROUP CONDITIONS

DESCRIPTION

The common 40 CFR Part 64 (CAM) requirements for these emission units are in this flexible group.

Emission Units: EUBOILER1, EUBOILER2

POLLUTION CONTROL EQUIPMENT

Pollution control equipment is described for each unit in EUBOILER1 and EUBOILER2.

I. EMISSION LIMIT(S)

NA

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

NA

IV. DESIGN/EQUIPMENT PARAMETER(S)

NA

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall assess opacity using USEPA Reference Method 9 - "Visual Determination of the Opacity of Emissions from Stationary Sources", upon the request of AQD.² **(R 336.1301)**

See Appendices 3-A and 5

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall utilize COMS-recorded opacity as an indicator of the emission unit's compliance with the particulate matter limit, except during periods of monitoring and system malfunction, system repairs or QA/QC activities. The appropriate range of opacity defining proper function of the PJFF is 0-20% opacity. An excursion is defined as any two (2) or more consecutive 1-hour block average opacity values greater than 15%. **(40 CFR 64.6(c)(1)(i) and (ii))**
2. The permittee shall continuously monitor and record any alarms and corrective actions taken. **(40 CFR 64.6(c)(1)(i) and (ii))**
3. The permittee shall properly maintain the COMS, including completing daily COMS zero and calibration tests; conduct necessary preventative maintenance; maintaining necessary parts for routine repairs of the monitoring equipment; and demonstrating adequate performance through an annual monitor audit. **(40 CFR 64.6(c)(1)(iii), 40 CFR 64.7(b))**

4. Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. The permittee shall operate the COMS during all required periods when the coal-fired boiler is operating. Data recorded during monitoring malfunctions, repair activities and QA/QC operations shall not be used for 40 CFR Part 64 compliance. **(40 CFR 64.6(c)(3), 40 CFR 64.7(c))**
5. The permittee shall conduct all required monitoring per the CAM Plan and otherwise satisfy the requirements specified in 40 CFR 64.7 through 40 CFR 64.9. **(40 CFR 64.6(c)(3), 40 CFR 64.7(a))**
6. The required COMS shall collect data for all required intervals when the emission unit is operating. **(40 CFR 64.7(c)(1)(iii))**
7. The permittee shall restore operation of the emission unit, control device, and associated pollutant capture system equipment to normal/compliant operation as quickly as possible, in accordance with good air pollution control practices for minimizing emissions in response to any noted exceedance or excursion. Excursions shall trigger an internal investigation, corrective action(s) per the MAP, and a CAM excursion summary reporting requirement. Necessary response shall include minimizing the period of any startup, shutdown or malfunction and taking necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of the excursion or exceedance (other than those caused by excused startup or shutdown conditions). **(40 CFR 64.7(d))**
8. If the permittee identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the permittee shall promptly notify the AQD and if necessary, submit a proposed modification of the ROP and CAM Plan to address the necessary monitoring changes. Such a modification may include but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters. **(40 CFR 64.7(e))**

See Appendices 3-A, 3-B and 3-D

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**
2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**
3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**
4. Quarterly reporting of monthly excess sulfur dioxide emissions (including the nature and cause of the periods of excess emissions), and of the dates and times of the monitoring systems being inoperative. Each quarterly report is due within 30 days of the calendar quarter reporting period. **(R 336.2170)**

5. Quarterly reporting of excess opacity emissions (including the nature and cause of the periods of excess emissions), and of the dates and times of the monitoring systems being inoperative. Each quarterly report is due within 30 days of the calendar quarter reporting period. **(R 336.2170)**
6. Each semiannual report of monitoring deviations shall include summary information on the number, duration, and cause of exceedances/excursions in the reporting period; and the corrective actions taken in response. If there were no excursions and/or exceedances in the reporting period, then this report shall include a statement that there were no excursions and/or exceedances. **(40 CFR 64.9(a)(2)(i))**
7. Each semiannual report of monitoring deviations shall include summary information on monitor downtime in the reporting period. If there were no periods of monitor downtime in the reporting period, then this report shall include a statement that there were no periods of monitor downtime. **(40 CFR 64.9(a)(2)(ii))**
8. Each semiannual report of monitoring deviations shall include a description of the actions taken to implement a Quality Improvement Plan (QIP) during the reporting period, if appropriate. If a QIP has been completed, the report shall include documentation that the QIP has been implemented, and a discussion pertaining to whether the QIP implementation has reduced the likelihood of excursions or exceedances. **(40 CFR 64.9(a)(2)(iii))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVBLR12	228 ²	400 ²	R 336.1225 R 336.2803 R 336.2804 40 CFR 52.21(c) and (d)

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with all applicable requirements of 40 CFR Part 64. **(40 CFR Part 64)**

Footnotes:

¹This condition is state only enforceable and was established pursuant to Rule 201(1)(b).

²This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

³This condition is federally enforceable and was originally established in the consent decree settling, "U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" and also pursuant to Act 451, Section 324.5503(b), and will remain in effect after termination of the consent decree.

⁴Definitions specific to this condition may be found in Appendix 1-B: Definitions Applicable to Specified Permit Conditions.

FGMATS_U12 FLEXIBLE GROUP CONDITIONS

DESCRIPTION

40 CFR Part 63, Subpart UUUUU (Mercury and Air Toxics Standards or MATS) requirements for existing coal-fired electric utility steam generating unit(s) (EGU) rated more than 25 megawatts electric (MWe) that serve(s) a generator producing electricity for sale and designed to burn coal that is not low rank virgin coal (calorific value of $\geq 8,300$ BTU/pound).

Emission Units: EUBOILER1 and EUBOILER2

POLLUTION CONTROL EQUIPMENT

EUBOILER1:

Low-NOx burners,
Sorbent injection (ACI) (activated carbon or other sorbent) for mercury control,
Dry sorbent injection (DSI) (hydrated lime or other sorbent) for acid gas control,
Pulse-jet fabric filter (PJFF) baghouse for PM control.

EUBOILER2:

Low-NOx burners,
Selective catalytic reduction (SCR),
Sorbent injection (ACI) (activated carbon or other sorbent) for mercury control,
Dry sorbent injection (DSI) (hydrated lime or other sorbent) for acid gas control,
Pulse-jet fabric filter (PJFF) baghouse for PM control.

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Filterable PM (per boiler)	0.030 lb/MMBTU*	Quarterly or Triennial Stack Test*	EUBOILER1 EUBOILER2	SC V.1	40 CFR 63.9991 40 CFR Part 63, Subpart UUUUU, Table 2.1.a
2. Hydrogen chloride (HCl) (per boiler)	0.0020 lb/MMBTU*	Quarterly or Triennial Stack Test*	EUBOILER1 EUBOILER2	SC V.2	40 CFR 63.9991 40 CFR Part 63, Subpart UUUUU, Table 2.1.b
3. Mercury (Hg) (per boiler)	1.2 lb/TBTU*	30-boiler operating day rolling arithmetic average updated at the end of each new boiler operating day	EUBOILER1 EUBOILER2	SC V.3 SC VI.3	40 CFR 63.9991 40 CFR Part 63, Subpart UUUUU, Table 2.1.c

* The emission limits apply at all times except during startup and shutdown.

+ If the unit(s) no longer meets the requirement for LEE status, the unit(s) will comply by stack testing quarterly until a continuous monitoring system has been installed, certified, and is operating.

4. If the permittee uses the provisions for low emitting EGU (LEE) status for any pollutant except Hg, performance test data must be collected showing average emissions less than 50% the of the applicable standard. **(40 CFR 63.10005(h)(1)(i))**

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall conduct a tune-up of each emission unit of FGMATS_U12 burner(s) and combustion controls, as applicable, at least every 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in 40 CFR 63.10021(e). **(40 CFR 63.10000(e), 40 CFR 63.10006(i), 40 CFR 63.10021(e))**
2. For the startup of any emission unit of FGMATS_U12 which will comply using paragraph (1) of the definition of "startup" in 40 CFR 63.10042, the permittee must use clean fuels as defined in 40 CFR 63.10042 for ignition. Once the emission unit(s) of FGMATS_U12 convert(s) to firing coal, residual oil, or solid oil-derived fuel, the permittee must engage all the applicable control technologies except dry scrubber and SCR. The permittee must start the dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. The permittee must comply with all applicable emission limits at all times except for periods that meet the applicable definitions of startup and shutdown in 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10042, 40 CFR Part 63, Subpart UUUUU, Table 3)**
3. During shutdown of any emission unit of FGMATS_U12 while firing coal, residual oil, or solid oil-derived fuel, the permittee must vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal, residual oil, or solid oil-derived fuel being fed into the applicable emission unit(s) of FGMATS_U12 and for as long as possible thereafter considering operational and safety concerns. In any case, the permittee must operate their controls when necessary to comply with other standards made applicable to the FGMATS_U12 by a permit limit or a rule other than 40 CFR Part 63, Subpart UUUUU and that require operation of the control devices. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the clean fuels defined in 40 CFR 63.10042 and must be used to the maximum extent possible taking into account considerations such as not compromising boiler or control device integrity. **(40 CFR 63.10042, 40 CFR Part 63, Subpart UUUUU, Table 3)**
4. The emission limits and operating limits in 40 CFR Part 63, Subpart UUUUU apply at all times except during periods of startup and shutdown; however, the applicable work practice requirements, which are specified in items 3 and 4 of Table 3 of 40 CFR Part 63, Subpart UUUUU must be met during periods of startup or shutdown. **(40 CFR 63.10000(a), 40 CFR Part 63, Subpart UUUUU, Table 3, 40 CFR 63.10022(a)(4))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall operate and maintain all associated air pollution control equipment and monitoring equipment necessary for compliance with 40 CFR Part 63, Subpart UUUUU in a manner consistent with safety and good air pollution control practices for minimizing emissions. **(40 CFR 63.10000(b))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall verify the filterable PM emission rates from each emission unit by testing at owner's expense, in accordance with 40 CFR 63.10007 and Table 5 to 40 CFR Part 63, Subpart UUUUU. The permittee must complete the test once every calendar quarter and at least 45 days since the previous performance test if not a LEE for PM. The permittee may skip performance testing in those quarters during which less than 168 boiler operating hours occur, except that a performance test must be conducted at least once every calendar year. **(40 CFR 63.10006(f), 40 CFR 63.10007, 40 CFR 63.10021(d)(1) and (2), 40 CFR Part 63, Subpart UUUUU, Table 5)**

2. The permittee shall verify the HCl emission rates from each emission unit by testing at owner's expense, in accordance with 40 CFR 63.10007 and Table 5 to 40 CFR Part 63, Subpart UUUUU. The permittee must complete the test once every calendar quarter and at least 45 days since the previous performance test if not a LEE for HCl. The permittee may skip performance testing in those quarters during which less than 168 boiler operating hours occur, except that a performance test must be conducted at least once every calendar year. **(40 CFR 63.10006(f), 40 CFR 63.10007, 40 CFR 63.10021(d)(1) and (2), 40 CFR Part 63, Subpart UUUUU, Table 5)**
3. If the permittee uses the provisions for LEE status for any pollutant except for Hg, the permittee shall verify each LEE pollutant emission rate from the applicable emission unit(s) of FGMATS_U12 by testing at owner's expense, in accordance with 40 CFR 63.10007 and Table 5 to 40 CFR Part 63, Subpart UUUUU. The permittee must complete the test once every 36 months and at least 1,050 days since the previous performance test to demonstrate continued LEE status. If a performance test deadline is missed due to the EGU being inoperative and 168 or more boiler operating hours occur in the next test period, an additional performance test shall be completed in the next test period, with at least 350 calendar days separating the performance tests conducted in the same 3-year period. **(40 CFR 63.10006(b), 40 CFR 63.10006(f), 40 CFR 63.10007, 40 CFR Part 63, Subpart UUUUU, Table 5)**
4. Unless an alternate schedule has been approved by the AQD, no less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing. The protocol shall describe the test method(s) and the maximum routine operating conditions, including targets for key operational parameters associated with air pollution control equipment to be monitored and recorded during testing, as applicable. **(40 CFR 63.7, 40 CFR 63.10007, 40 CFR 63.10030(a))**

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. During startup, as defined by paragraph (1) of the definition of "startup" in 40 CFR 63.10042, the permittee must operate all Continuous Monitoring Systems (CMS). Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). The permittee must comply with the applicable emission limits at all times except for startup and shutdown periods unless the permittee chooses to use just one set of sorbent traps to demonstrate compliance with the applicable Hg emission limit, then the permittee must comply with the applicable Hg emission limit at all times. The permittee must collect monitoring data during startup periods, as specified in 40 CFR 63.10020(a) and (b). The permittee must keep records during startup periods, as provided in 40 CFR 63.10032 and 40 CFR 63.10021(h). Any fraction of an hour in which startup occurs constitutes a full hour of startup. **(40 CFR Part 63, Subpart UUUUU, Table 3)**
2. The permittee must operate all CMS during shutdown. The permittee must also collect appropriate data, and the permittee must calculate the pollutant emission rate for each hour of shutdown for those pollutants for which a CMS is used. The permittee must collect monitoring data during shutdown periods, as specified in 40 CFR 63.10020(a). The permittee must keep records during shutdown periods, as provided in 40 CFR 63.10032 and 40 CFR 63.10021(h). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. **(40 CFR Part 63, Subpart UUUUU, Table 3)**
3. For any emission unit not relying on the LEE provisions for Hg, the permittee shall install, calibrate, maintain and operate a device to monitor and record the Hg concentration from each emission unit on a continuous basis. The permittee shall install and operate the Hg CEMS or sorbent trap monitoring system to meet the timelines, requirements and reporting detailed in Appendix A of 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10000(c)(1)(vi))**
4. If required to convert measured pollutant concentrations to the units of the applicable mass per heat input emission limit(s) or for routine operation of a sorbent trap monitoring system, the permittee shall install, calibrate, maintain and operate a device to monitor and record the oxygen (O₂) or carbon dioxide (CO₂) exhaust gas content, exhaust gas flow rate and/or moisture from each emission unit on a continuous basis. The monitor shall be operated in accordance with procedures outlined in 40 CFR Part 75, Appendices A and B. As an alternative

to moisture monitoring, the permittee may elect to use appropriate fuel-specific default moisture values from 40 CFR 75.11(b) for coal-fired units or a default moisture value for non-coal-fired units as established via petition to the Administrator under 40 CFR 75.66. **(40 CFR 63.10010(b)-(d), 40 CFR Part 63, Subpart UUUUU, Table 5)**

5. For any emission unit not relying on the LEE provisions for Hg, the permittee shall keep, in a satisfactory manner, hourly (if applicable) and 30-day rolling average Hg emission rate records for each emission unit **OR** (30-day (or 90-day if emission averaging (as applicable)) rolling weighted average Hg emission rate records for the combination of units participating in an averaging plan) excluding periods of startup and shutdown. **(40 CFR 63.10010, 40 CFR 63.10021, 40 CFR Part 63, Subpart UUUUU, Table 7)**
6. The permittee must operate the required monitoring system(s) and collect data at all required intervals at all times that the affected EGU is operating, except for periods of monitoring system malfunctions or out-of-control periods (see 40 CFR 63.8(c)(7) of 40 CFR Part 63, Subpart A), and required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments. The permittee is required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable. **(40 CFR 63.10020(b))**
7. The permittee may not use data recorded during startup or shutdown in calculations used to report emissions, except as otherwise provided in 40 CFR 63.10000(c)(1)(vi)(B) and 40 CFR 63.10005(a)(2)(iii). In addition, data recorded during monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods or required monitoring system quality assurance or control activities may not be used in calculations used to report emissions or operating levels. The permittee must use all of the quality-assured data collected during all other periods in assessing the operation of the control device and associated control system. **(40 CFR 63.10020(c))**
8. Failure to collect required data is a deviation from the monitoring requirements except for periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments. **(40 CFR 63.10020(d))**
9. If the permittee uses CEMS to measure SO₂, PM, HCl, HF, or Hg emissions (or sorbent trap monitoring system), except as otherwise provided in 40 CFR 63.10020(c), the permittee must demonstrate continuous compliance by using all quality-assured hourly data recorded by the CEMS (or sorbent trap monitoring system) and other required monitoring systems to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if alternate emissions averaging is used for Hg, a 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. Use Equation 8 in 40 CFR 63.10021(b) to determine the 30- or 90-boiler operating day rolling average. **(40 CFR 63.10021(a) and (b))**
10. The permittee must keep the following records:
 - a. A copy of each notification and report that has been submitted to comply with 40 CFR Part 63, Subpart UUUUU, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that has been submitted, according to the requirements in 40 CFR 63.10(b)(2)(xiv). **(40 CFR 63.10032(a)(1))**
 - b. Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in 40 CFR 63.10(b)(2)(viii). **(40 CFR 63.10032(a)(2))**
 - c. For each CEMS and CPMS, the permittee must keep the following records:
 - i. Records described in 40 CFR 63.10(b)(2)(vi) through (xi). **(40 CFR 63.10032(b)(1))**
 - ii. Previous (i.e., superseded) versions of the performance evaluation plan as required in 40 CFR 63.8(d)(3). **(40 CFR 63.10032(b)(2))**
 - iii. Request for alternatives to relative accuracy test for CEMS as required in 40 CFR 63.8(f)(6)(i). **(40 CFR 63.10032(b)(3))**
 - iv. The date and time that each deviation started and stopped and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period. **(40 CFR 63.10032(b)(4))**

- v. If the permittee continuously monitors Hg and/or HCl and/or HF emissions, the permittee must also keep the records required under Appendix A and/or Appendix B of 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10032(a))**
 - d. For each emission unit subject to an emission limit:
 - i. The permittee shall keep the monthly fuel use by each emission unit, including the type(s) of fuel and amount(s) used. **(40 CFR 63.10032(d)(1))**
 - ii. If the permittee combusts non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR 241.3(b)(1), the permittee must keep a record which documents how the secondary material meets each of the legitimacy criteria. If the permittee combusts a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR 241.3(b)(2), the permittee must keep records as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR 241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under 40 CFR 241.3(c), the permittee must keep a record which documents how the fuel satisfies the requirements of the petition process. **(40 CFR 63.10032(d)(2))**
 - iii. For an emission unit that qualifies as a LEE under 40 CFR 63.10005(h), the permittee shall keep annual records that document that the emissions in the previous stack test(s) continue to qualify the unit for LEE status for an applicable pollutant, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the pollutant to increase within the past year. **(40 CFR 63.10032(d)(3))**
 - e. Regarding startup periods or shutdown periods:
 - i. If the permittee chooses to rely on paragraph (1) of the definition of “startup” in 40 CFR 63.10042 for the emission unit(s), the permittee shall keep records of the occurrence and duration of each startup or shutdown. **(40 CFR 63.10032(f)(1))**
 - ii. The type(s) and amount(s) of fuel used during each startup or shutdown. **(40 CFR 63.10032(i))**
 - f. The occurrence and duration of each malfunction of an operation (i.e., process equipment) or the air pollution control and monitoring equipment. **(40 CFR 63.10032(g))**
 - g. Actions taken during periods of malfunction to minimize emissions in accordance with 40 CFR 63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation. **(40 CFR 63.10032(h))**
 - h. If the permittee elects to average emissions consistent with 40 CFR 63.10009, the permittee shall keep a copy of the emissions averaging implementation plan required in 40 CFR 63.10009(g), all calculations required under 40 CFR 63.10009, including daily records of heat input or steam generation, as applicable, and monitoring records consistent with 40 CFR 63.10022. **(40 CFR 63.10032(e))**
11. The permittee shall keep all records in a form suitable and readily available for expeditious review and for at least 5 years after the date of each occurrence, corrective action, report, or record. The records must be kept onsite for at least 2 years and may be kept offsite for the remaining 3 years. **(40 CFR 63.10(b)(1), 40 CFR 63.10033)**
12. The permittee shall maintain on site and submit, if requested by the Administrator, an annual report of periodic performance tune-ups containing the information required by 40 CFR 63.10021(e)(8). The reports shall be in a format acceptable to the Administrator. If requested by the AQD District Supervisor, the permittee shall also submit an annual report with the results of the performance tune-ups. **(40 CFR 63.10021(e)(8))**

VII. REPORTING

- 1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**
- 2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**
4. Semiannual reporting of the information required in 40 CFR 63.10031(c)(1) through (9), (d), and (e) as applicable. The report shall be postmarked or received by the Administrator by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. The report shall include the following:
 - a. The information required by the Continuous Monitoring Summary Report located in 40 CFR 63.10(e)(3)(vi). **(40 CFR 63.10031(c)(1))**
 - b. The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by USEPA or the basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure. **(40 CFR 63.10031(c)(2))**
 - c. Indicate whether any emission unit in FGMATS_U12 burned new types of fuel during the reporting period. If new types of fuel were burned, include the date of the performance test where that fuel was in use. **(40 CFR 63.10031(c)(3))**
 - d. Include the date of the most recent tune-up for each emission unit. The date of the tune-up is the date the tune-up provisions specified in 40 CFR 63.10021(e)(6) and (7) were completed. **(40 CFR 63.10031(c)(4))**
 - e. Report emergency bypass information annually from units with LEE status. **(40 CFR 63.10031(c)(6))**
 - f. A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during the test, if applicable. If the permittee is conducting stack tests once every 3 years to maintain LEE status, consistent with 40 CFR 63.10006(b), the report shall include the date of each stack test conducted during the previous 3 years, a comparison of emission level the permittee achieved in each stack test conducted during the previous 3 years to the 50% emission limit threshold required in 40 CFR 63.10005(h)(1)(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions. **(40 CFR 63.10031(c)(7))**
 - g. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to FGMATS_U12 and there are no deviations from the requirements for work practice standards in Table 3 to 40 CFR Part 63, Subpart UUUUU that apply to FGMATS_U12, the report shall include a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, and operating parameter monitoring systems, were out-of-control as specified in 40 CFR 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period. **(40 CFR Part 63, Subpart UUUUU, Table 8)**
 - h. If there is a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain a brief description of the deviation, the duration of the deviation, the cause of the deviation, and the information in 40 CFR 63.10031(d). If there were periods during which the CMS's, including continuous emissions monitoring systems and continuous parameter monitoring systems, were out-of-control, as specified in 40 CFR 63.8(c)(7), the report must contain the information in 40 CFR 63.10031(e). **(40 CFR 63.10031(c)(1) through (9), (d), and (e), 40 CFR 63.10031(a), 40 CFR 63.10031(c)(9), 40 CFR Part 63, Subpart UUUUU, Table 8)**
 - i. If the affected source submits a compliance report pursuant to Table 8 in 40 CFR Part 63, Subpart UUUUU, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in 40 CFR Part 63, Subpart UUUUU, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report required by SC VII.2. **(40 CFR 63.10031(e))**
5. The permittee must submit any of the following applicable notifications by the dates specified within the specific citation: 40 CFR 63.7(b) and (c) Notification of performance test and Quality assurance program; 40 CFR 63.8(e) Performance evaluation of continuous monitoring systems; 40 CFR 63.8(f)(4) Request to use alternative monitoring methods; 40 CFR 63.8(f)(6) Alternative to the relative accuracy test; 40 CFR 63.9(b) Initial

notifications; 40 CFR 63.9(c) Request for extension of compliance; 40 CFR 63.9(d) Notification that source is subject to special compliance requirements; 40 CFR 63.9(e) Notification of performance test, which shall be submitted at least 30 days before the performance test is scheduled to begin; 40 CFR 63.9(f) Notification of opacity and visible emission observations; 40 CFR 63.9(g) Additional notification requirements for sources with continuous monitoring systems; and 40 CFR 63.9(h) Notification of compliance status. **(40 CFR 63.10030(a))**

6. On or after July 1, 2020, within 60 days after the date of completing each performance test, the permittee must submit the performance test reports required by this subpart to USEPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through USEPA's Central Data Exchange (CDX) (www.epa.gov/cdx). Performance test data must be submitted in the file format generated through use of USEPA's Electronic Reporting Tool (ERT) (see <http://www.epa.gov/ttn/chief/ert/index.html>). Only data collected using those test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. At the discretion of the AQD, the permittee must also submit these reports, one to the Technical Programs Unit Supervisor and one to the AQD District Supervisor, in a format approved by the AQD. **(40 CFR 63.10031(f))**
7. On or after July 1, 2020, within 60 days after the date of completing each CEMS (SO₂, PM, HCl, HF, and Hg) performance evaluation test, as defined in 40 CFR 63.2, the permittee must submit the relative accuracy test audit (RATA) data (or, for PM CEMS, RCA and RRA data) required by this subpart to USEPA's WebFIRE database by using CEDRI that is accessed through USEPA's CDX (www.epa.gov/cdx). The RATA data shall be submitted in the file format generated through use of USEPA's Electronic Reporting Tool (ERT) (<http://www.epa.gov/ttn/chief/ert/index.html>). Only RATA data compounds listed on the ERT Web site are subject to this requirement. At the discretion of the AQD, the permittee must also submit these RATA reports to the AQD District Supervisor in a format approved by the AQD. Owners or operators shall submit calibration error testing, drift checks, and other information required in the performance evaluation as described in 40 CFR 63.2 and as required in this chapter. **(40 CFR 63.10031(f)(1))**
8. On or after July 1, 2020, for a PM CEMS, PM CPMS, or approved alternative monitoring using a HAP metals CEMS, within 60 days after the reporting periods ending on March 31, June 30, September 30, and December 31, the permittee must submit quarterly reports to USEPA's WebFIRE database by using the CEDRI that is accessed through USEPA's CDX (www.epa.gov/cdx). The permittee must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with USEPA's reporting form output format. For each reporting period, the quarterly reports must include all of the calculated 30-boiler operating day rolling average values derived from the CEMS and PM CPMS. **(40 CFR 63.10031(f)(2))**
9. Reports for a SO₂ CEMS, a Hg CEMS or sorbent trap monitoring system, a HCl or HF CEMS, and any supporting monitors for such systems (such as a diluent or moisture monitor) shall be submitted using the ECMPs Client Tool, as provided for in 40 CFR Part 63, Subpart UUUUU, Appendices A and B and 40 CFR 63.10021(f). **(40 CFR 63.10031(f)(3))**
10. On or after July 1, 2020, the permittee must submit all reports required by 40 CFR 63.10031 (c) and (d) electronically using CEDRI that is accessed through the USEPA's Central Data Exchange (CDX) (www.epa.gov/cdx). The permittee must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with USEPA's reporting form output format. If requested by the AQD, the permittee must also submit these reports to the AQD District Supervisor in a format approved by the AQD. **(40 CFR 63.10031(f)(4))**
11. Prior to July 1, 2020, all reports subject to electronic submittal in SC VII.6, VII.7, VII.8 and VII.10 shall be submitted to the USEPA at the frequency specified in those paragraphs in electronic portable document format (PDF) using the ECMPs Client Tool. Each PDF version of a submitted report must include sufficient information to assess compliance and to demonstrate that the testing was done properly. The data elements listed at 40 CFR 63.10031(f)(6)(i)-(xii) must be entered into the ECMPs Client Tool at the time of submission of each PDF file. **(40 CFR 63.10031(f)(6))**
12. If requested by the Administrator, the permittee must submit the monitoring plan (or relevant portion of the plan) at least 60 days before the initial performance evaluation of a particular CMS, except where the CMS has already

undergone a performance evaluation that meets the requirements of 40 CFR 63.10010 (e.g., if the CMS was previously certified under another program). **(40 CFR 63.10000(d)(3))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

1. For each emission unit or emissions averaging group complying with an emission limit as specified in Table 2 of 40 CFR Part 63, Subpart UUUUU, the permittee may request to switch from a mass per heat input to a mass per gross output limit (or vice versa).
 - a. The permittee may switch from a mass per heat input to a mass per gross output limit (or vice-versa), provided that:
 - i. The permittee submits a request that identifies for each emission unit or emissions averaging group involved in the proposed switch both the current and proposed emission limit. **(40 CFR 63.10030(e)(7)(iii)(A)(1))**
 - ii. The request arrives to the Administrator at least 30 calendar days prior to the date that the switch is proposed to occur. **(40 CFR 63.10030(e)(7)(iii)(A)(2))**
 - iii. The request demonstrates through performance stack test results completed within 30 days prior to the submission, compliance for each emission unit or emissions averaging group with both the mass per heat input and mass per gross output limits. **(40 CFR 63.10030(e)(7)(iii)(A)(3))**
 - iv. The permittee revises and submits all other applicable plans, e.g., monitoring and emissions averaging, with the request. **(40 CFR 63.10030(e)(7)(iii)(A)(4))**
 - v. The permittee maintains records of all information regarding the choice of emission limits. **(40 CFR 63.10030(e)(7)(iii)(A)(5))**
 - b. The permittee may begin to use the revised emission limits starting in the next reporting period, after receipt of written acknowledgement from the Administrator of the switch. **(40 CFR 63.10030(e)(7)(iii)(B))**
 - c. From the submission of the request until start of the next reporting period after receipt of written acknowledgement from the Administrator of the switch, the permittee shall demonstrate compliance with both the mass per heat input and mass per gross output emission limits for each pollutant for each emission unit or emissions averaging group. **(40 CFR 63.10030(e)(7)(iii)(C))**
2. If using a CMS to demonstrate continuous compliance with an emission limit or operating limit, the permittee must develop a site-specific monitoring plan and submit this site-specific monitoring plan, if requested, at least 60 days before the initial performance evaluation (where applicable) of the CMS. This requirement also applies to the permittee if the permittee petitions the Administrator for alternative monitoring parameters under 40 CFR 63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and CPMS prepared under Appendix B of 40 CFR Part 60 or 40 CFR Part 75, and that meet the requirements of 40 CFR 63.10010. Using the process described in 40 CFR 63.8(f)(4), the permittee may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in this paragraph of this section and, if approved, include those in the site-specific monitoring plan. The monitoring plan must address the following provisions: **(40 CFR 63.10000(d), 40 CFR 63.10010)**
 - a. Installation of the CMS or sorbent trap monitoring system sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device). See 40 CFR 63.10010(a) for further details. For PM CPMS installations, follow the procedures in 40 CFR 63.10010(h).

- b. Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems.
 - c. Schedule for conducting initial and periodic performance evaluations.
 - d. Performance evaluation procedures and acceptance criteria (e.g., calibrations), including the quality control program in accordance with the general requirements of 40 CFR 63.8(d).
 - e. On-going operation and maintenance procedures, in accordance with the general requirements of 40 CFR 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii).
 - f. Conditions that define a CMS that is out of control consistent with 40 CFR 63.8(c)(7)(i) and for responding to out of control periods consistent with 40 CFR 63.8(c)(7)(ii) and (c)(8).
 - g. On-going recordkeeping and reporting procedures, in accordance with the general requirements of 40 CFR 63.10(c), (e)(1), and (e)(2)(i), or as specifically required under 40 CFR Part 63, Subpart UUUUU.
 - h. Alternatively, the requirements are considered to be met for a particular CMS or sorbent trap monitoring system if:
 - i. The CMS or sorbent trap monitoring system is installed, certified, maintained, operated, and quality-assured either according to 40 CFR Part 75, or Appendix A or B of 40 CFR Part 63, Subpart UUUUU; and
 - ii. The recordkeeping and reporting requirements of 40 CFR Part 75, or Appendix A or B of 40 CFR Part 63, Subpart UUUUU, which pertain to the CMS, are met.
3. If the permittee chooses to reapply for LEE status, the permittee must demonstrate all performance tests and CEMS or sorbent trap monitoring system data over a consecutive 3-year period show compliance with the LEE criteria. **(40 CFR 63.10006(b)(2) and (h))**
4. If any emission unit(s) cease(s) to operate in a manner that causes the unit(s) to meet the definition of an EGU subject to 40 CFR Part 63, Subpart UUUUU, the permittee must submit the notification in 40 CFR 63.10000(i)(2) no less than 30 days prior to when the EGU will cease complying with 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10000(i)(2), 40 CFR 63.10030(f))**
5. The permittee shall comply with all provisions of the National Emission Standards for Hazardous Air Pollutants as specified in 40 CFR Part 63, Subparts A and UUUUU. **(40 CFR Part 63, Subparts A and UUUUU)**

Footnotes:

¹ This condition is state only enforceable and was established pursuant to Rule 201(1)(b).

² This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

FGMATS_U3 FLEXIBLE GROUP CONDITIONS

DESCRIPTION

40 CFR Part 63, Subpart UUUUU (Mercury and Air Toxics Standards or MATS) requirements for existing coal-fired electric utility steam generating unit(s) (EGU) rated more than 25 megawatts electric (MWe) that serve(s) a generator producing electricity for sale and designed to burn coal that is not low rank virgin coal (calorific value of $\geq 8,300$ BTU/pound).

Emission Unit: EUBOILER3

POLLUTION CONTROL EQUIPMENT

Low-NOx burners,
Selective catalytic reduction (SCR),
Sorbent injection (ACI) (activated carbon or other sorbent for mercury control),
Spray dry absorber (SDA) for acid gas control,
Pulse-jet fabric filter (PJFF) baghouse for PM control.

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Filterable PM	0.030 lb/MMBTU*	30-day boiler operating day rolling arithmetic average updated at the end of each new boiler operating day	EUBOILER3	SC VI.3 SC VI.7 SC VI.8	40 CFR 63.9991 40 CFR Part 63, Subpart UUUUU, Table 2.1.a
2. SO ₂	0.20 lb/MMBTU*	30-boiler operating day rolling arithmetic average updated at the end of each new boiler operating day	EUBOILER3	SC VI.2 SC VI.6 SC VI.7 SC VI.10 SC VI.14	40 CFR 63.9991 40 CFR Part 63, Subpart UUUUU, Table 2.1.b
3. Mercury (Hg)	1.2 lb/TBTU*	30-boiler operating day rolling arithmetic average updated at the end of each new boiler operating day	EUBOILER3	SC V.1 SC VI.4 SC VI.7 SC VI.9 SC VI.14	40 CFR 63.9991 40 CFR Part 63, Subpart UUUUU, Table 2.1.c

* The emission limits apply at all times except during startup and shutdown

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

- The permittee shall conduct a tune-up of each emission unit of FGMATS_U3 burner(s) and combustion controls, as applicable, at least every 36 calendar months, or each 48 calendar months if neural network combustion

optimization software is employed, as specified in 40 CFR 63.10021(e). **(40 CFR 63.10000(e), 40 CFR 63.10006(i), 40 CFR 63.10021(e))**

2. For the startup of any emission unit of FGMATS_U3 which will comply using paragraph (1) of the definition of “startup” in 40 CFR 63.10042, the permittee must use clean fuels as defined in 40 CFR 63.10042 for ignition. Once the emission unit(s) of FGMATS_U3 convert(s) to firing coal, residual oil, or solid oil-derived fuel, the permittee must engage all the applicable control technologies except dry scrubber and SCR. The permittee must start the dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. The permittee must comply with all applicable emission limits at all times except for periods that meet the applicable definitions of startup and shutdown in 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10042, 40 CFR Part 63, Subpart UUUUU, Table 3)**
3. During shutdown of any emission unit of FGMATS_U3 while firing coal, residual oil, or solid oil-derived fuel, the permittee must vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal, residual oil, or solid oil-derived fuel being fed into the applicable emission unit(s) of FGMATS_U3 and for as long as possible thereafter considering operational and safety concerns. In any case, the permittee must operate their controls when necessary to comply with other standards made applicable to the FGMATS_U3 by a permit limit or a rule other than 40 CFR Part 63, Subpart UUUUU and that require operation of the control devices. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the clean fuels defined in 40 CFR 63.10042 and must be used to the maximum extent possible taking into account considerations such as not compromising boiler or control device integrity. **(40 CFR 63.10042, 40 CFR Part 63, Subpart UUUUU, Table 3)**
4. The emission limits and operating limits in 40 CFR Part 63, Subpart UUUUU apply at all times except during periods of startup and shutdown; however, the applicable work practice requirements, which are specified in items 3 and 4 of Table 3 of 40 CFR Part 63, Subpart UUUUU must be met during periods of startup or shutdown. **(40 CFR 63.10000(a), 40 CFR Part 63, Subpart UUUUU, Table 3)**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall operate and maintain all associated air pollution control equipment and monitoring equipment necessary for compliance with 40 CFR Part 63, Subpart UUUUU in a manner consistent with safety and good air pollution control practices for minimizing emissions. **(40 CFR 63.10000(b))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

NA

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. During startup, as defined by paragraph (1) of the definition of “startup” in 40 CFR 63.10042, the permittee must operate all Continuous Monitoring Systems (CMS). Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). The permittee must comply with the applicable emission limits at all times except for startup and shutdown periods unless the permittee chooses to use just one set of sorbent traps to demonstrate compliance with the applicable Hg emission limit, then the permittee must comply with the applicable Hg emission limit at all times. The permittee must collect monitoring data during startup periods, as specified in 40 CFR 63.10020(a) and (b). The permittee must keep records during startup periods, as provided in 40 CFR 63.10032 and 40 CFR 63.10021(h). Any fraction of an hour in which startup occurs constitutes a full hour of startup. **(40 CFR Part 63, Subpart UUUUU, Table 3)**

2. The permittee must operate all CMS during shutdown. The permittee must also collect appropriate data, and the permittee must calculate the pollutant emission rate for each hour of shutdown for those pollutants for which a CMS is used. The permittee must collect monitoring data during shutdown periods, as specified in 40 CFR 63.10020(a). The permittee must keep records during shutdown periods, as provided in 40 CFR 63.10032 and 40 CFR 63.10021(h). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. **(40 CFR Part 63, Subpart UUUUU, Table 3)**
3. The permittee shall install, calibrate, maintain and operate a device to monitor and record the PM concentration of the exhaust gas from each emission unit on a continuous basis. The permittee shall install and operate the PM CEMS to meet the timelines, requirements and reporting detailed in Performance Specification 11 in 40 CFR Part 60, Appendix B and Procedure 2 in 40 CFR Part 60, Appendix F. **(40 CFR 63.10010(i), 40 CFR Part 63, Subpart UUUUU, Table 5)**
4. The permittee shall install, calibrate, maintain and operate a device to monitor and record the Hg concentration from each emission unit on a continuous basis. The permittee shall install and operate the Hg CEMS or sorbent trap monitoring system to meet the timelines, requirements and reporting detailed in Appendix A of 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10000(c)(1)(vi))**
5. The permittee shall install, maintain, and operate a device(s) to monitor and record the SO₂ concentration of the exhaust gas from each emission unit on a continuous basis. The permittee shall install and operate each CEMS to meet the timelines, requirements and reporting detailed in 40 CFR Part 75, Appendices A and B. **(40 CFR 63.10000(c)(1)(v))**
6. If required to convert measured pollutant concentrations to the units of the applicable mass per heat input emission limit(s) or for routine operation of a sorbent trap monitoring system, the permittee shall install, calibrate, maintain and operate a device to monitor and record the oxygen (O₂) or carbon dioxide (CO₂) exhaust gas content, exhaust gas flow rate and/or moisture from each emission unit on a continuous basis. The monitor shall be operated in accordance with procedures outlined in 40 CFR Part 75, Appendices A and B. As an alternative to moisture monitoring, the permittee may elect to use appropriate fuel-specific default moisture values from 40 CFR 75.11(b) for coal-fired units or a default moisture value for non-coal-fired units as established via petition to the Administrator under 40 CFR 75.66. **(40 CFR 63.10010(b)-(d), 40 CFR Part 63, Subpart UUUUU, Table 5)**
7. If the permittee elects to use a PM CEMS or participate in an averaging plan for PM, total non-Hg HAP metals, or individual metals, the permittee shall keep, in a satisfactory manner, hourly (if applicable) and 30-day rolling average PM, total non-Hg HAP metals, or individual metals (as applicable) emission rate records for each emission unit excluding periods of startup and shutdown. **(40 CFR 63.10010, 40 CFR 63.10021, 40 CFR Part 63, Subpart UUUUU, Table 7)**
8. For any emission unit not relying on the LEE provisions for Hg, the permittee shall keep, in a satisfactory manner, hourly (if applicable) and 30-day rolling average Hg emission rate records for each emission unit excluding periods of startup and shutdown. **(40 CFR 63.10010, 40 CFR 63.10021, 40 CFR Part 63, Subpart UUUUU, Table 7)**
9. The permittee shall keep, in a satisfactory manner, hourly and 30-day rolling average SO₂ emission rate records for each emission unit excluding periods of startup and shutdown. **(40 CFR 63.10010, 40 CFR 63.10021, 40 CFR Part 63, Subpart UUUUU, Table 7)**
10. The permittee must operate the required monitoring system(s) and collect data at all required intervals at all times that the affected EGU is operating, except for periods of monitoring system malfunctions or out-of-control periods (see 40 CFR 63.8(c)(7) of 40 CFR Part 63, Subpart A), and required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments. The permittee is required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable. **(40 CFR 63.10020(b))**

11. The permittee may not use data recorded during startup or shutdown in calculations used to report emissions, except as otherwise provided in 40 CFR 63.10000(c)(1)(vi)(B) and 40 CFR 63.10005(a)(2)(iii). In addition, data recorded during monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods or required monitoring system quality assurance or control activities may not be used in calculations used to report emissions or operating levels. The permittee must use all of the quality-assured data collected during all other periods in assessing the operation of the control device and associated control system. **(40 CFR 63.10020(c))**
12. Failure to collect required data is a deviation from the monitoring requirements except for periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments. **(40 CFR 63.10020(d))**
13. If the permittee uses CEMS to measure SO₂, PM, HCl, HF, or Hg emissions (or sorbent trap monitoring system), except as otherwise provided in 40 CFR 63.10020(c), the permittee must demonstrate continuous compliance by using all quality-assured hourly data recorded by the CEMS (or sorbent trap monitoring system) and other required monitoring systems to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if alternate emissions averaging is used for Hg, a 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. Use Equation 8 in 40 CFR 63.10021(b) to determine the 30- or 90-boiler operating day rolling average. **(40 CFR 63.10021(a) and (b))**
14. The permittee must keep the following records:
 - a. A copy of each notification and report that has been submitted to comply with 40 CFR Part 63, Subpart UUUUU, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that has been submitted, according to the requirements in 40 CFR 63.10(b)(2)(xiv). **(40 CFR 63.10032(a)(1))**
 - b. Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in 40 CFR 63.10(b)(2)(viii). **(40 CFR 63.10032(a)(2))**
 - c. For each CEMS and CPMS, the permittee must keep the following records:
 - i. Records described in 40 CFR 63.10(b)(2)(vi) through (xi). **(40 CFR 63.10032(b)(1))**
 - ii. Previous (i.e., superseded) versions of the performance evaluation plan as required in 40 CFR 63.8(d)(3). **(40 CFR 63.10032(b)(2))**
 - iii. Request for alternatives to relative accuracy test for CEMS as required in 40 CFR 63.8(f)(6)(i). **(40 CFR 63.10032(b)(3))**
 - iv. The date and time that each deviation started and stopped and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period. **(40 CFR 63.10032(b)(4))**
 - v. If the permittee continuously monitors Hg and/or HCl and/or HF emissions, the permittee must also keep the records required under Appendix A and/or Appendix B of 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10032(a))**
 - d. For each emission unit subject to an emission limit:
 - i. The permittee shall keep the monthly fuel use by each emission unit, including the type(s) of fuel and amount(s) used. **(40 CFR 63.10032(d)(1))**
 - ii. If the permittee combusts non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR 241.3(b)(1), the permittee must keep a record which documents how the secondary material meets each of the legitimacy criteria. If the permittee combusts a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR 241.3(b)(2), the permittee must keep records as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR 241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under 40 CFR 241.3(c), the permittee must keep a record which documents how the fuel satisfies the requirements of the petition process. **(40 CFR 63.10032(d)(2))**

- e. Regarding startup periods or shutdown periods:
 - i. If the permittee chooses to rely on paragraph (1) of the definition of “startup” in 40 CFR 63.10042 for the emission unit(s), the permittee shall keep records of the occurrence and duration of each startup or shutdown. **(40 CFR 63.10032(f)(1))**
 - ii. The type(s) and amount(s) of fuel used during each startup or shutdown. **(40 CFR 63.10032(i))**
 - f. The occurrence and duration of each malfunction of an operation (i.e., process equipment) or the air pollution control and monitoring equipment. **(40 CFR 63.10032(g))**
 - g. Actions taken during periods of malfunction to minimize emissions in accordance with 40 CFR 63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation. **(40 CFR 63.10032(h))**
15. The permittee shall keep all records in a form suitable and readily available for expeditious review and for at least 5 years after the date of each occurrence, corrective action, report, or record. The records must be kept onsite for at least 2 years and may be kept offsite for the remaining 3 years. **(40 CFR 63.10(b)(1), 40 CFR 63.10033)**
16. The permittee shall maintain on site and submit, if requested by the Administrator, an annual report of periodic performance tune-ups containing the information required by 40 CFR 63.10021(e)(8). The reports shall be in a format acceptable to the Administrator. If requested by the AQD District Supervisor, the permittee shall also submit an annual report with the results of the performance tune-ups. **(40 CFR 63.10021(e)(8))**

VII. REPORTING

- 1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**
- 2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**
- 3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**
- 4. Semiannual reporting of the information required in 40 CFR 63.10031(c)(1) through (9), (d), and (e) as applicable. The report shall be postmarked or received by the Administrator by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. The report shall include the following:
 - a. The information required by the Continuous Monitoring Summary Report located in 40 CFR 63.10(e)(3)(vi). **(40 CFR 63.10031(c)(1))**
 - b. The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by USEPA or the basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure. **(40 CFR 63.10031(c)(2))**
 - c. Indicate whether any emission unit in FGMATS_U3 burned new types of fuel during the reporting period. If new types of fuel were burned, include the date of the performance test where that fuel was in use. **(40 CFR 63.10031(c)(3))**
 - d. Include the date of the most recent tune-up for each emission unit. The date of the tune-up is the date the tune-up provisions specified in 40 CFR 63.10021(e)(6) and (7) were completed. **(40 CFR 63.10031(c)(4))**
 - e. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to FGMATS_U3 and there are no deviations from the requirements for work practice standards in Table 3 to 40 CFR Part 63, Subpart UUUUU that apply to FGMATS_U3, the report shall include a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, and operating parameter monitoring systems, were out-of-control as specified in 40 CFR 63.8(c)(7), a statement

that there were no periods during which the CMSs were out-of-control during the reporting period. **(40 CFR Part 63, Subpart UUUUU, Table 8)**

- f. If there is a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain a brief description of the deviation, the duration of the deviation, the cause of the deviation, and the information in 40 CFR 63.10031(d). If there were periods during which the CMS's, including continuous emissions monitoring systems and continuous parameter monitoring systems, were out-of-control, as specified in 40 CFR 63.8(c)(7), the report must contain the information in 40 CFR 63.10031(e). **(40 CFR 63.10031(c)(1) through (9), (d), and (e), 40 CFR 63.10031(a), 40 CFR 63.10031(c)(9), 40 CFR Part 63, Subpart UUUUU, Table 8)**
 - g. If the affected source submits a compliance report pursuant to Table 8 in 40 CFR Part 63, Subpart UUUUU, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in 40 CFR Part 63, Subpart UUUUU, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report required by SC VII.2. **(40 CFR 63.10031(e))**
- 5. The permittee must submit any of the following applicable notifications by the dates specified within the specific citation: 40 CFR 63.7(b) and (c) Notification of performance test and Quality assurance program; 40 CFR 63.8(e) Performance evaluation of continuous monitoring systems; 40 CFR 63.8(f)(4) Request to use alternative monitoring methods; 40 CFR 63.8(f)(6) Alternative to the relative accuracy test; 40 CFR 63.9(b) Initial notifications; 40 CFR 63.9(c) Request for extension of compliance; 40 CFR 63.9(d) Notification that source is subject to special compliance requirements; 40 CFR 63.9(e) Notification of performance test, which shall be submitted at least 30 days before the performance test is scheduled to begin; 40 CFR 63.9(f) Notification of opacity and visible emission observations; 40 CFR 63.9(g) Additional notification requirements for sources with continuous monitoring systems; and 40 CFR 63.9(h) Notification of compliance status. **(40 CFR 63.10030(a))**
 - 6. On or after July 1, 2020, within 60 days after the date of completing each performance test, the permittee must submit the performance test reports required by this subpart to USEPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through USEPA's Central Data Exchange (CDX) (www.epa.gov/cdx). Performance test data must be submitted in the file format generated through use of USEPA's Electronic Reporting Tool (ERT) (see <http://www.epa.gov/ttn/chief/ert/index.html>). Only data collected using those test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. At the discretion of the AQD, the permittee must also submit these reports, one to the Technical Programs Unit Supervisor and one to the AQD District Supervisor, in a format approved by the AQD. **(40 CFR 63.10031(f))**
 - 7. On or after July 1, 2020, for a PM CEMS, PM CPMS, or approved alternative monitoring using a HAP metals CEMS, within 60 days after the reporting periods ending on March 31, June 30, September 30, and December 31, the permittee must submit quarterly reports to USEPA's WebFIRE database by using the CEDRI that is accessed through USEPA's CDX (www.epa.gov/cdx). The permittee must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with USEPA's reporting form output format. For each reporting period, the quarterly reports must include all of the calculated 30-boiler operating day rolling average values derived from the CEMS and PM CPMS. **(40 CFR 63.10031(f)(2))**
 - 8. Reports for a SO₂ CEMS, a Hg CEMS or sorbent trap monitoring system, a HCl or HF CEMS, and any supporting monitors for such systems (such as a diluent or moisture monitor) shall be submitted using the ECMPS Client Tool, as provided for in 40 CFR Part 63, Subpart UUUUU, Appendices A and B and 40 CFR 63.10021(f). **(40 CFR 63.10031(f)(3))**
 - 9. On or after July 1, 2020, the permittee must submit all reports required by 40 CFR 63.10031 (c) and (d) electronically using CEDRI that is accessed through the USEPA's Central Data Exchange (CDX) (www.epa.gov/cdx). The permittee must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with USEPA's reporting form output format. If requested by the AQD, the permittee must also submit these reports, to the AQD District Supervisor in a format approved by the AQD. **(40 CFR 63.10031(f)(4))**

10. Prior to July 1, 2020, all reports subject to electronic submittal in SC VII.6, VII.7, and VII.9 shall be submitted to the USEPA at the frequency specified in those paragraphs in electronic portable document format (PDF) using the ECMPS Client Tool. Each PDF version of a submitted report must include sufficient information to assess compliance and to demonstrate that the testing was done properly. The data elements listed at 40 CFR 63.10031(f)(6)(i)-(xii) must be entered into the ECMPS Client Tool at the time of submission of each PDF file. **(40 CFR 63.10031(f)(6))**
11. If requested by the Administrator, the permittee must submit the monitoring plan (or relevant portion of the plan) at least 60 days before the initial performance evaluation of a particular CMS, except where the CMS has already undergone a performance evaluation that meets the requirements of 40 CFR 63.10010 (e.g., if the CMS was previously certified under another program). **(40 CFR 63.10000(d)(3))**

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

1. For each emission unit or emissions averaging group complying with an emission limit as specified in Table 2 of 40 CFR Part 63, Subpart UUUUU, the permittee may request to switch from a mass per heat input to a mass per gross output limit (or vice versa).
 - a. The permittee may switch from a mass per heat input to a mass per gross output limit (or vice-versa), provided that:
 - i. The permittee submits a request that identifies for each emission unit or emissions averaging group involved in the proposed switch both the current and proposed emission limit. **(40 CFR 63.10030(e)(7)(iii)(A)(1))**
 - ii. The request arrives to the Administrator at least 30 calendar days prior to the date that the switch is proposed to occur. **(40 CFR 63.10030(e)(7)(iii)(A)(2))**
 - iii. The request demonstrates through performance stack test results completed within 30 days prior to the submission, compliance for each emission unit or emissions averaging group with both the mass per heat input and mass per gross output limits. **(40 CFR 63.10030(e)(7)(iii)(A)(3))**
 - iv. The permittee revises and submits all other applicable plans, e.g., monitoring and emissions averaging, with the request. **(40 CFR 63.10030(e)(7)(iii)(A)(4))**
 - v. The permittee maintains records of all information regarding the choice of emission limits. **(40 CFR 63.10030(e)(7)(iii)(A)(5))**
 - b. The permittee may begin to use the revised emission limits starting in the next reporting period, after receipt of written acknowledgement from the Administrator of the switch. **(40 CFR 63.10030(e)(7)(iii)(B))**
 - c. From the submission of the request until start of the next reporting period after receipt of written acknowledgement from the Administrator of the switch, the permittee shall demonstrate compliance with both the mass per heat input and mass per gross output emission limits for each pollutant for each emission unit or emissions averaging group. **(40 CFR 63.10030(e)(7)(iii)(C))**
2. If using a CMS to demonstrate continuous compliance with an emission limit or operating limit, the permittee must develop a site-specific monitoring plan and submit this site-specific monitoring plan, if requested, at least 60 days before the initial performance evaluation (where applicable) of the CMS. This requirement also applies to the permittee if the permittee petitions the Administrator for alternative monitoring parameters under 40 CFR 63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and CPMS prepared under Appendix B of 40 CFR Part 60 or 40 CFR Part 75, and that meet the requirements of 40 CFR 63.10010. Using the process described in 40 CFR 63.8(f)(4), the permittee may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in this paragraph of this section and, if approved, include those in the

site-specific monitoring plan. The monitoring plan must address the following provisions: **(40 CFR 63.10000(d), 40 CFR 63.10010)**

- a. Installation of the CMS or sorbent trap monitoring system sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device). See 40 CFR 63.10010(a) for further details. For PM CPMS installations, follow the procedures in 40 CFR 63.10010(h).
 - b. Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems.
 - c. Schedule for conducting initial and periodic performance evaluations.
 - d. Performance evaluation procedures and acceptance criteria (e.g., calibrations), including the quality control program in accordance with the general requirements of 40 CFR 63.8(d).
 - e. On-going operation and maintenance procedures, in accordance with the general requirements of 40 CFR 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii).
 - f. Conditions that define a CMS that is out of control consistent with 40 CFR 63.8(c)(7)(i) and for responding to out of control periods consistent with 40 CFR 63.8(c)(7)(ii) and (c)(8).
 - g. On-going recordkeeping and reporting procedures, in accordance with the general requirements of 40 CFR 63.10(c), (e)(1), and (e)(2)(i), or as specifically required under 40 CFR Part 63, Subpart UUUUU.
 - h. Alternatively, the requirements are considered to be met for a particular CMS or sorbent trap monitoring system if:
 - i. The CMS or sorbent trap monitoring system is installed, certified, maintained, operated, and quality-assured either according to 40 CFR Part 75, or Appendix A or B of 40 CFR Part 63, Subpart UUUUU; and
 - ii. The recordkeeping and reporting requirements of 40 CFR Part 75, or Appendix A or B of 40 CFR Part 63, Subpart UUUUU, which pertain to the CMS, are met.
3. If any emission unit(s) cease(s) to operate in a manner that causes the unit(s) to meet the definition of an EGU subject to 40 CFR Part 63, Subpart UUUUU, the permittee must submit the notification in 40 CFR 63.10000(i)(2) no less than 30 days prior to when the EGU will cease complying with 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10000(i)(2), 40 CFR 63.10030(f))**
4. The permittee shall comply with all provisions of the National Emission Standards for Hazardous Air Pollutants as specified in 40 CFR Part 63, Subparts A and UUUUU. **(40 CFR Part 63, Subparts A and UUUUU)**

Footnotes:

¹ This condition is state only enforceable and was established pursuant to Rule 201(1)(b).

² This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

FGEXISTINGRICE FLEXIBLE GROUP CONDITIONS

DESCRIPTION

Existing Emergency Engines located at a Major Source < 500 HP, Commenced Construction or Reconstruction before June 12, 2006.

These four (4) existing stationary diesel-fired reciprocating compression ignition internal combustion engines are emergency generators subject to 40 CFR Part 63, Subpart ZZZZ (National Emission Standard for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines (RICE)).

Emission Units: EUCATFIREPUMP3, EUHPHSWP15001, EUHPHSWP15002, EUHPHSWP3000.

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMITS

NA

II. MATERIAL LIMIT(S)

Material	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Fuel Oil – sulfur content	1.0% by weight at 18,000 BTU/lb	Instantaneous; at all times	EUCATFIREPUMP3 EUHPHSWP15001 EUHPHSWP15002 EUHPHSWP3000	SC VI.5	R 336.1401(1), Table 41

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. Each engine in FGEXISTINGRICE shall be installed, maintained, and operated in a satisfactory manner. A list of recommended work practice standards as specified in 40 CFR 63.6602 and Table 2c, Item 1 or the permittee may petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices. The following are the recommended work practices specified in 40 CFR Part 63, Subpart ZZZZ, Table 2c:
 - a. Change oil and filter every 500 hours of operation or annually, whichever comes first, except as allowed in SC III.3.
 - b. Inspect the air cleaner every 1,000 hours of operation or annually, whichever comes first; and replace as necessary.
 - c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

If the emergency engine is being operated during an emergency and it is not possible to shut down the engine to perform the work practice standards on the schedule required the work practice standard can be delayed until the emergency is over. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State or local law has been abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, State or local law or which the risk was deemed unacceptable. **(40 CFR 63.6602, 40 CFR Part 63, Subpart ZZZZ, Table 2c, Item 6)**

2. The permittee may utilize an oil analysis program in order to extend the specified oil change requirement. The oil analysis must be performed at the same frequency as oil changes are required. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c of 40 CFR Part 63, Subpart ZZZZ. **(40 CFR 63.6625(i))**
3. The permittee shall maintain and operate each engine in FGEXISTINGRICE per the manufacturer's emission related written instructions or develop a maintenance plan which must provide for the maintenance and operation of the engine in a manner consistent with good air pollution control practices for minimizing emissions. **(40 CFR 63.6625(e), 40 CFR 63.6640(a), 40 CFR Part 63, Subpart ZZZZ, Table 6 Item 9)**
4. The permittee shall minimize the time spent at idle during startup and minimize the startup time of each engine in FGEXISTINGRICE to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup apply. **(40 CFR 63.6625(h))**
5. There is no time limit on the use of emergency stationary RICE in emergency situations. **(40 CFR 63.6640(f)(1))**
6. The permittee may not operate each engine in FGEXISTINGRICE for more than 100 hours per calendar year for the purpose of necessary maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The permittee may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing. A petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency internal combustion engines beyond 100 hours per calendar year. **(40 CFR 63.6640(f)(2))**
7. The permittee may operate each engine in FGEXISTINGRICE for up to 50 hours per calendar year in non-emergency situations, but those 50 hours are counted towards the 100 hours per calendar year provided for maintenance and testing as provided in 40 CFR 63.6640 (f)(2). The 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income to supply non-emergency power as part of a financial arrangement with another entity, except as allowed in 40 CFR 63.6640(f)(4)(ii). **(40 CFR 63.6640(f)(4))**
8. If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable. **(40 CFR Part 63, Table 2c, Footnote 1)**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall equip and maintain with a non-resettable hour meter to track the number of hours each engine operates. **(40 CFR 63.6625(f))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. If using the oil analysis program in order to extend the specified oil change requirement in 40 CFR Part 63, Subpart ZZZZ, Table 2d, the permittee must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20% from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner

or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine. **(40 CFR 63.6625(j))**

See Appendix 5

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. For each engine in FGEXISTINGRICE, the permittee shall keep in a satisfactory manner, records of the occurrence and duration of each malfunction of operation or the air pollution control monitoring equipment. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 63.6655(a)(2), 40 CFR 63.6660)**
2. For each engine in FGEXISTINGRICE, the permittee shall keep in a satisfactory manner, records of actions taken during periods of malfunction to minimize emissions, including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 63.6655(a)(5), 40 CFR 63.6660)**
3. For each engine in FGEXISTINGRICE, the permittee shall keep in a satisfactory manner, maintenance records to demonstrate compliance with SC III.1 and the written maintenance plan. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 63.6655(d), 40 CFR 63.6655(e), 40 CFR 63.6660)**
4. The permittee shall monitor and record the total hours of operation for each engine in FGEXISTINGRICE per calendar year, recorded through the non-resettable hours meter, in a manner acceptable to the District Supervisor, Air Quality Division. The permittee shall document how many hours are spent for emergency operation; including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purposes specified in 40 CFR 63.6640(f)(4)(ii), the permittee must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation. **(40 CFR 63.6655(f))**
5. The permittee shall maintain sufficient records to demonstrate that the sulfur content for each shipment of fuel oil received is less than 1.0% by weight. **(R 336.1213(3))**
6. The permittee shall conduct and maintain records of a daily (non-certified) visual observation for opacity in order to verify proper firing, whenever an engine is in use for 24 consecutive hours or more. **(R 336.1213(3))**
7. The permittee shall maintain a record of the applicability determination for each engine in FGEXISTINGRICE relative to the requirements of 40 CFR Part 63, Subparts A and ZZZZ. **(40 CFR Part 63, Subpart A, Section 63.10(b)(3))**

See Appendix 3-C

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**
2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**
4. The permittee shall submit to the AQD District Supervisor, a semiannual compliance report, as specified in 40 CFR 63.6650, which contains all deviations during the reporting period from any applicable emission limitation or operating limitation. If there are no deviations from any applicable emission limitations or operating limitations, the report shall contain a statement that there were no deviations during the reporting period. The first report shall cover the period beginning on the applicable compliance date specified in 40 CFR 63.6595 and ending on June 30 (postmarked or delivered by July 31) or December 31 (postmarked or delivered by January 31), whichever date is the first date following the end of the first calendar half after the applicable compliance date. Each subsequent report must cover the semiannual period from January 1 through June 30, or from July 1 through December 31. The subsequent reports must be postmarked or delivered by July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period, except as allowed in 40 CFR 63.6650(b)(5). The compliance report must also contain the following information, as specified in 40 CFR 63.6650(c) and (d):
 - a. Company name and address.
 - b. Certification of the report by a responsible official.
 - c. Date of report and beginning and ending dates of the reporting period.
 - d. The number of malfunctions, including a brief description of each event, that occurred during the reporting period and a demonstration that the Malfunction Plan was followed during such events.
 - e. The total operating time of the RICE at which the deviation occurred during the reporting period.
 - f. The number, duration, and cause of deviations and the corrective action taken.

A copy of the compliance report shall be kept on file for a period of at least five years (at least two years at the site) and made available to the Department upon request. **(40 CFR 63.6640(b), 40 CFR 63.6650(b),(c),(d), 40 CFR 63.6660)**

5. Each affected source that has obtained a Title V operating permit pursuant to 40 CFR Part 70 or 71 must report all deviations as defined in 40 CFR Part 63, Subpart ZZZZ in the semiannual monitoring report required by 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to Table 7 of 40 CFR Part 63, Subpart ZZZZ along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in 40 CFR Part 63, Subpart ZZZZ, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority. **(40 CFR 63.6650(f))**
 - c. For each engine in FGEXISTINGRICE that is an emergency stationary engine with a site rating of more than 100 brake hp that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in 40 CFR 63.6640(f)(4)(ii), you must submit an annual report according to the requirements below and as specified in 40 CFR 63.6650(h). **(40 CFR 63.6650(h), 40 CFR 63.6660)**
 - a. The report must contain the following information:
 - i. Company name and address where the engine is located.
 - ii. Date of the report and beginning and ending dates of the reporting period.
 - iii. Engine site rating and model year.
 - iv. Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.
 - v. Hours operated for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii).
 - vi. Number of hours the engine is contractually obligated to be available for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii).

- vii. Hours spent for operation for the purpose specified in 40 CFR 63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in 40 CFR 63.6640(f)(4)(ii). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.
 - viii. If there were no deviations from the fuel requirements in 40 CFR 63.6604 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.
 - ix. If there were deviations from the fuel requirements in 40 CFR 63.6604 that apply to the engine (if any), information on the number, duration, and cause of deviations, and the corrective action taken.
- b. The permittee shall submit annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through USEPA's Central Data Exchange (CDX) (www.epa.gov/cdx). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in 40 CFR 63.13.

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with all applicable provisions of the National Emission Standards for Hazardous Air Pollutants, as specified in 40 CFR Part 63, Subparts A and ZZZZ, for Stationary Reciprocating Internal Combustion Engines by the initial compliance date of May 3, 2013. **(40 CFR 63.6595(a)(1), 40 CFR, Part 63, Subparts A and ZZZZ)**

Footnotes:

¹ This condition is state only enforceable and was established pursuant to Rule 201(1)(b).

² This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

FGNEWCIRICE FLEXIBLE GROUP CONDITIONS

DESCRIPTION

EUWPDIESEL: A Water Pump for EUSDA_U3 emergency flush certified to NSPS IIII Tier 3 requirements. A diesel-powered, stationary internal combustion engine rated at 130 HP (97 kW).

EUTRNCNTRDIESEL: An emergency generator for the Training Center with diesel engine certified to NSPS IIII Tier 3 requirements. A diesel-powered, stationary internal combustion engine rated at 1,193 bHP.

These units are subject to the provisions of 40 CFR Part 60, Subpart IIII and 40 CFR Part 63, Subpart ZZZZ.

Emission Units: EUWPDIESEL, EUTRNCNTRDIESEL

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. NMHC + NOx	4.0 g/kW-hr ²	Hourly	EUWPDIESEL	SC V.1 SC VI.2	40 CFR 60.4205(b), 40 CFR 89.112(a) Table 1
2. CO	5.0 g/kW-hr ²	Hourly	EUWPDIESEL	SC V.1 SC VI.2	40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 89.112(a) Table 1
3. PM	0.30 g/kW-hr ²	Hourly	EUWPDIESEL	SC V.1 SC VI.2	40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 89.112(a) Table 1
4. NMHC + NOx	6.4 g/kW-hr ²	Hourly	EUTRNCNTRDIESEL	SC V.1 SC VI.2	40 CFR 60.4205(c)
5. CO	3.5 g/kW-hr ²	Hourly	EUTRNCNTRDIESEL	SC V.1 SC VI.2	40 CFR 60.4205(c)
6. PM	0.20 g/kW-hr ²	Hourly	EUTRNCNTRDIESEL	SC V.1 SC VI.2	40 CFR 60.4205(c)

II. MATERIAL LIMIT(S)

- The permittee shall burn only diesel fuel, in EUWPDIESEL and EUTRNCNTRDIESEL with the maximum sulfur content of 15 ppm (0.0015%) by weight and a minimum Cetane index of 40 or a maximum aromatic content of 35 volume percent.² (R 336.1205(1)(a), R 336.1402(1), 40 CFR 60.4207(b), 40 CFR 80.510(b))

See Appendix 3-C

III. PROCESS/OPERATIONAL RESTRICTION(S)

- The permittee shall not operate EUWPDIESEL for more than 100 hours per year on a 12-month rolling time period basis as determined at the end of each calendar month. The 100 hours includes the hours for the purpose

of emergency operation, necessary maintenance checks and readiness testing as described in SC III.2.² **(R 336.1205(1)(a), R 336.1225, R 336.1702(a))**

2. The permittee may operate not either EUWPDIESEL or EUTRNCNTRDIESEL for no more than 100 hours per calendar year for the purpose of necessary maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. The permittee may petition the Department for approval of additional hours to be used for maintenance checks and readiness testing. A petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency internal combustion engines beyond 100 hours per calendar year. EUWPDIESEL may operate up to 50 hours per calendar year in non-emergency situations, but those 50 hours are counted towards the 100 hours per calendar year provided for maintenance and testing.² **(40 CFR 60.4211(f))**
3. If EUWPDIESEL and/or EUTRNCNTRDIESEL is a certified engine, the permittee shall meet the following requirements:
 - a. Operate and maintain the certified engine and control device according to the manufacturer's emission-related written instructions;
 - b. Change only those emission-related settings that are permitted by the manufacturer; and
 - c. Meet the requirements as specified in 40 CFR 89, 94, and/or 1068, as they apply to each engine in FGNEWCIRICE.

If you do not operate and maintain the certified engine and control device according to the manufacturer's emission-related written instructions, the engine may be considered a non-certified engine.² **(40 CFR 60.4211(a))**

4. If EUWPDIESEL and/or EUTRNCNTRDIESEL is a non-certified engine or a certified engine operating in a non-certified manner, the permittee shall keep a maintenance plan and records of conducted maintenance for EUWPDIESEL and must, to the extent practicable, maintain and operate each engine in FGNEWCIRICE in a manner consistent with good air pollution control practice for minimizing emissions.² **(40 CFR 60.4211(g)(2))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall equip and maintain EUWPDIESEL and EUTRNCNTRDIESEL with a non-resettable hours meter to track the operating hours.² **(R 336.1205(1)(a), R 336.1225, 40 CFR 60.4209)**
2. The nameplate capacity of EUWPDIESEL shall not exceed 130 hp, as certified by the equipment manufacturer.² **(R 336.1205(1)(a), R 336.1225, 40 CFR 60.4202, 40 CFR 89.112(a))**
3. The nameplate capacity of EUTRNCNTRDIESEL shall not exceed the capacity restrictions (560<kW<=2237) as certified by the equipment manufacturer. **(40 CFR 60.4202)**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. Unless EUWPDIESEL and/or EUTRNCNTRDIESEL has been certified by the manufacturer as required by 40 CFR Part 60, Subpart IIII and the permittee maintains the engine as required by 40 CFR 60.4211, the permittee shall conduct an initial performance test to demonstrate compliance with the emission limits in SC I.1 – I.3 for each diesel engine, within one year after startup, or within 1 year after either diesel engine is no longer configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after the permittee changes emission-related settings in a way that is not permitted by the manufacturer, to demonstrate compliance with the emission limits in 40 CFR 60.4205(b). If a performance test is required, the performance test shall be conducted according to 40 CFR 60.4212. No less than 30 days prior to testing, a complete test plan shall be submitted to the AQD. The final plan must be approved by the AQD prior to testing. After conducting the initial performance test, the permittee shall conduct subsequent performance testing, for non-certified engines, every 8,760 hours or 3 years, whichever comes first. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The permittee shall notify the AQD Technical Programs Unit Supervisor and the District Supervisor not less than 7 days of the time and place before performance tests are conducted. Verification of emission rates

includes the submittal of a complete report of the test results to the AQD within 60 days following the last date of the test.² **(R 336.2001, R 336.2003, R 336.2004, 40 CFR 60.4211(g)(2), 40 CFR 60.4212)**

2. Upon request of the AQD District Supervisor, the permittee shall verify NO_x, CO, PM₁₀, and PM_{2.5} emission rates from EUWPDIESEL or EUTRNCNTRDIESEL by testing at owner's expense, in accordance with the Department requirements. Testing shall be performed using an approved USEPA Method listed in:

Pollutant	Test Method Reference
PM ₁₀ /PM _{2.5}	40 CFR Part 51, Appendix M
NO _x	40 CFR Part 60, Appendix A
CO	40 CFR Part 60, Appendix A

An alternate method, or a modification to the approved USEPA Method, may be specified in an AQD-approved Test Protocol. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. The permittee shall notify the AQD Technical Programs Unit Supervisor and the District Supervisor not less than 7 days of the time and place before performance tests are conducted. The permittee must submit a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test.² **(R 336.1205, R 336.1225, R 336.2001, R 336.2003, R 336.2004)**

See Appendix 5

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall complete all required calculations in a format acceptable to the AQD District Supervisor by the 30th day of the calendar month, for the previous calendar month, unless otherwise specified in any monitoring/recordkeeping special condition.² **(R 336.1205(1)(a))**
2. The permittee shall keep, in a satisfactory manner, records of testing required in SC V.1 or manufacturer certification documentation indicating that EUWPDIESEL and EUTRNCNTRDIESEL meets the applicable requirements contained in the federal Standards of Performance for New Stationary Sources 40 CFR Part 60, Subpart IIII. If EUWPDIESEL or EUTRNCNTRDIESEL becomes uncertified then the permittee must also keep records of a maintenance plan and maintenance activities. The permittee shall keep all records on file and make them available to the Department upon request.² **(40 CFR 60.4211(g)(2))**
3. The permittee shall monitor and record the total hours of operation and the hours of operation during non-emergencies for EUWPDIESEL and EUTRNCNTRDIESEL, on a monthly and 12-month rolling time period basis, in a manner acceptable to the AQD District Supervisor. The permittee shall document how many hours are spent for emergency operation of EUWPDIESEL and EUTRNCNTRDIESEL, including what classified the operation as emergency and how many hours are spent maintenance or readiness testing and for non-emergency operation.² **(R 336.1205(1)(a), 40 CFR 60.4211, 40 CFR 60.4214(b))**
4. The permittee shall keep, in a satisfactory manner, fuel supplier certification records or fuel sample test data, for each delivery of diesel fuel oil used in EUWPDIESEL and EUTRNCNTRDIESEL, demonstrating that the fuel meets the requirement of 40 CFR 80.510(b). The certification or test data shall include the name of the oil supplier or laboratory, the sulfur content, and cetane index or aromatic content of the fuel oil.² **(R 336.1205(1)(a), R 336.1402(1), 40 CFR 80.510(b))**

See Appendices 3, 4, and 7

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**
3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**
4. The permittee shall submit any performance test reports to the AQD Technical Programs Unit and District Office, in a format approved by the AQD. **(R 336.1213(3)(c), R 336.2001(5))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVWPDIESEL	14 ²	16 ²	40 CFR 52.21(c) & (d)

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the provisions of the federal Standards of Performance for New Stationary Sources as specified in 40 CFR Part 60, Subparts A and IIII, as they apply to EUWPDIESEL and EUTRNCNTRDIESEL.² **(40 CFR Part 60, Subparts A & IIII, 40 CFR 63.6590)**
2. The permittee shall comply with the provisions of the National Emission Standards for Hazardous Air Pollutants, as specified in 40 CFR Part 63, Subparts A and ZZZZ, as they apply to EUWPDIESEL and EUTRNCNTRDIESEL.² **(40 CFR Part 63, Subparts A and ZZZZ, 40 CFR 63.6595)**

Footnotes:

¹ This condition is state only enforceable and was established pursuant to Rule 201(1)(b).

² This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

FGAUXBLRS3 FLEXIBLE GROUP CONDITIONS

DESCRIPTION

Two (2) distillate oil fired boilers rated at 9.8 MMBTU heat input, providing heat to Plant 3. These units are subject to the provisions of 40 CFR Part 63, Subpart DDDDD.

Emission Units: EUAUXBLR3B, EUAUXBLR3C (Both are 9.8 MMBTU/hr, Diesel fuel)

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

NA

II. MATERIAL LIMIT(S)

Material	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Fuel Oil – sulfur content	0.4% by weight at 18,000 BTU/lb	Instantaneous; at all times	EUAUXBLR3B EUAUXBLR3C	SC VI.1	R 336.1282 (b)(ii)

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee must meet the tune-up and energy assessment work practice standards for each applicable boiler or process heater at the source. **(40 CFR 63.7500(a)(1), 40 CFR Part 63, Subpart DDDDD, Table 3, Nos. 1-4)**
2. The permittee must operate and maintain affected sources in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the AQD that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. **(40 CFR 63.7500(a)(3))**
3. The permittee may obtain approval from the USEPA Administrator to use an alternative to the tune-up and energy assessment work practice standards. **(40 CFR 63.7500(b))**
4. The permittee must conduct a biennial performance tune-up according to 40 CFR 63.7540(a)(11) as stated in SC III.5, respectively. Each biennial tune-up specified in 40 CFR 63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. **(40 CFR 63.7515(d))**
5. Boilers or process heaters with a heat input capacity of less than 10 million BTU per hour must conduct a biennial tune-up of the boiler or process heater. **(40 CFR 63.7540(a)(11), 40 CFR 63.7500(e))**
6. The permittee shall conduct the tune-up within 30 days of startup, if the unit is not operating on the required date for a tune-up. **(40 CFR 63.7540(a)(12))**
7. The permittee must demonstrate continuous compliance with the tune-up requirement by completing the following: **(40 CFR 63.7540(a)(10))**

- a. Inspect the burner, and clean or replace any components of the burner as necessary (the permittee may delay the burner inspection until the next scheduled unit shutdown). At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment. **(40 CFR 63.7540(a)(10)(i))**
- b. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available. **(40 CFR 63.7540(a)(10)(ii))**
- c. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (the permittee may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection. **(40 CFR 63.7540(a)(10)(iii))**
- d. Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO_x requirement to which the unit is subject. **(40 CFR 63.7540(a)(10)(iv))**
- e. Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer. **(40 CFR 63.7540(a)(10)(v))**
- f. Maintain on-site and submit, if requested by the AQD, the most recent periodic report containing the information as listed below. **(40 CFR 63.7540(a)(10)(vi))**
 - i. The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater. **(40 CFR 63.7540(a)(10)(vi)(A))**
 - ii. A description of any corrective actions taken as a part of the tune-up. **(40 CFR 63.7540(a)(10)(vi)(B))**
 - iii. The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit. **(40 CFR 63.7540(a)(10)(vi)(C))**
8. The permittee must complete the Initial tune ups on all affected units except as provided in 40 CFR 63.7510(j) and 40 CFR 63.7540(a)(13). **(40 CFR 63.7510(e))**
9. For affected sources (as defined in 40 CFR 63.7490) that have not operated since the previous compliance demonstration and more than one year has passed since the previous compliance demonstration, the permittee must complete a subsequent tune-up within 30 days of startup by following the procedures described in SC III.7.a through SC III.7.f. **(40 CFR 63.7515(9))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

NA

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

NA

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall maintain sufficient records to demonstrate that the sulfur content for each shipment of fuel oil received is less than 0.4% by weight. **(R 336.1213(3))**
2. The permittee must keep a copy of each notification and report submitted to comply with 40 CFR Part 63, Subpart DDDDD, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that the permittee submitted, according to the requirements in 40 CFR 63.10(b)(2)(xiv). **(40 CFR 63.7555(a)(1))**
3. The permittee must keep each record on site, or they must be accessible from on-site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record. The permittee can keep the records off site for the remaining 3 years. **(40 CFR 63.7560(a), (b), and (c))**

See Appendix 3-C (Fuel Oil Sulfur Monitoring)

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**
2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**
3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**
4. The permittee must submit boiler tune-up compliance reports. Compliance reports must be postmarked or submitted by March 15 of the year following the tune-up and must cover the applicable 1, 2, or 5-year period starting from January 1 of the year following the previous tune-up to December 31 (of the latest tune-up year). Compliance reports must be submitted using the Compliance and Emissions Data Reporting Interface (CEDRI) which is accessed through the USEPA's Central Data Exchange (CDX) (www.epa.gov/cdx). If the reporting form is not available in CEDRI at the time the compliance report is due, a hardcopy of the compliance report shall be submitted to the state and USEPA Region 5. At the discretion of the Administrator, the permittee must submit these reports in the format specified by the Administrator. **(40 CFR 63.7550(b), 40 CFR 63.10(a)(5), 40 CFR 63.7550(h)(3))**
5. Unless the USEPA Administrator has approved a different schedule for submission of reports under 40 CFR 63.10(a), the permittee must submit each report, according to paragraph (h) of 40 CFR 63.7550, stated in SC VII.5, by the date in Table 9 of 40 CFR Part 63, Subpart DDDDD and according to the requirements in paragraphs (b)(1) through (4) of 40 CFR 63.7550, as listed below. For units that are subject only to a requirement to conduct a 5-year tune-up according to 40 CFR 63.7540(a)(12), stated in SC IX.5.b, and not subject to emission limits or operating limits, the permittee may submit only a 5-year compliance report, as specified in paragraphs (b)(1) through (4) of 40 CFR 63.7550, as listed below, instead of a semi-annual compliance report. **(40 CFR 63.7550(a) & (b))**
 - a. Each semi-annual compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. 5-year compliance reports must cover the 5-year period from January 1 to December 31. **(40 CFR 63.7550(b)(3))**
 - b. Each semi-annual compliance report must be postmarked or submitted no later than September 15 or March 15, whichever date is the first date following the end of the semiannual reporting period. 5-year compliance reports must be postmarked or submitted no later than March 15. **(40 CFR 63.10(a)(5), 40 CFR 63.7550(b)(4), 40 CFR 63.7550(b)(5))**

6. The permittee must include the following information in the compliance report. **(40 CFR 63.7550(a) & (c))**
 - a. If the facility is subject to the requirements of a tune up the permittee must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii), (xiv), and (xvii) of 40 CFR 63.7550. **(40 CFR 63.7550(c)(1))**
 - b. 40 CFR 63.7550(c)(5) is as follows:
 - i. Company and Facility name and address. **(40 CFR 63.7550(c)(5)(i))**
 - ii. Process unit information, emissions limitations, and operating parameter limitations. **(40 CFR 63.7550(c)(5)(ii))**
 - iii. Date of report and beginning and ending dates of the reporting period. **(40 CFR 63.7550(c)(5)(iii))**
 - iv. Include the date of the most recent tune-up for each unit subject to only the requirement to conduct a 5-year tune-up according to 40 CFR 63.7540(a)(12), stated in SC IX.5.b. Include the date of the most recent burner inspection if it was not done on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown. **(40 CFR 63.7550(c)(5)(xiv))**
 - v. Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report. **(40 CFR 63.7550(c)(5)(xvii))**
7. The permittee must submit the reports according to the procedures specified in paragraph (h)(3) of 40 CFR 63.7550, as listed below. **(40 CFR 63.7550(h))**
 - a. The permittee must submit all reports required by Table 9 of 40 CFR Part 63, Subpart DDDDD electronically to the USEPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the USEPA's CDX.) The permittee must use the appropriate electronic report in CEDRI for 40 CFR Part 63, Subpart DDDDD. Instead of using the electronic report in CEDRI for 40 CFR Part 63, Subpart DDDDD, the permittee may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (<http://www.epa.gov/ttn/chief/cedri/index.html>), once the XML schema is available. If the reporting form specific to 40 CFR Part 63, Subpart DDDDD is not available in CEDRI at the time that the report is due, the permittee must submit the report to the Administrator at the appropriate address listed in 40 CFR 63.13. The permittee must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI. **(40 CFR 63.7550(h)(3))**
8. The permittee must report each instance in which the permittee did not meet each applicable operating limit in Tables 3 and 4 to 40 CFR Part 63, Subpart DDDDD. These instances are deviations from the operating limits, respectively, in 40 CFR Part 63, Subpart DDDDD. These deviations must be reported according to the requirements in Section 63.7550. **(40 CFR 63.7540(b))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the applicable requirements of 40 CFR Part 63, Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. **(40 CFR Part 63, Subparts A and DDDDD)**
2. The permittee must be in compliance with the work practice standards (tune ups, energy assessment) in 40 CFR Part 63, Subpart DDDDD. **(40 CFR 63.7505(a))**
3. The permittee shall comply with the General Provisions in 40 CFR 63.1 through 40 CFR 63.15 apply to this source as indicated in Table 10 of 40 CFR Part 63, Subpart DDDDD. **(40 CFR 63.7565, Table 10)**

Footnotes:

¹ This condition is state only enforceable and was established pursuant to Rule 201(1)(b).

² This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

FGPARTSCLEANERS FLEXIBLE GROUP CONDITIONS

DESCRIPTION

Any cold cleaner that is grandfathered or exempt from Rule 201 pursuant to Rule 278, 278a and Rule 281(2)(h) or Rule 285(2)(r)(iv). Existing cold cleaners were placed into operation prior to July 1, 1979. New cold cleaners were placed into operation on or after July 1, 1979.

Emission Unit: EUPARTSCLEANERS

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

NA

II. MATERIAL LIMIT(S)

1. The permittee shall not use cleaning solvents containing more than five % by weight of the following halogenated compounds: methylene chloride, perchloroethylene, trichloroethylene, 1,1,1-trichloroethane, carbon tetrachloride, chloroform, or any combination thereof. **(R 336.1213(2))**

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. Cleaned parts shall be drained for no less than 15 seconds or until dripping ceases. **(R 336.1611(2)(b), R 336.1707(3)(b))**
2. The permittee shall perform routine maintenance on each cold cleaner as recommended by the manufacturer. **(R 336.1213(3))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The cold cleaner must meet one of the following design requirements:
 - a. The air/vapor interface of the cold cleaner is no more than ten square feet. **(R 336.1281(2)(h))**
 - b. The cold cleaner is used for cleaning metal parts and the emissions are released to the general in-plant environment. **(R 336.1285((2)(r)(iv))**
2. The cold cleaner shall be equipped with a device for draining cleaned parts. **(R 336.1611(2)(b), R 336.1707(3)(b))**
3. All new and existing cold cleaners shall be equipped with a cover and the cover shall be closed whenever parts are not being handled in the cold cleaner. **(R 336.1611(2)(a), R 336.1707(3)(a))**
4. The cover of a new cold cleaner shall be mechanically assisted if the Reid vapor pressure of the solvent is more than 0.3 psia or if the solvent is agitated or heated. **(R 336.1707(3)(a))**
5. If the Reid vapor pressure of any solvent used in a new cold cleaner is greater than 0.6 psia; or, if any solvent used in a new cold cleaner is heated above 120 degrees Fahrenheit, then the cold cleaner must comply with at least one of the following provisions:

- a. The cold cleaner must be designed such that the ratio of the freeboard height to the width of the cleaner is equal to or greater than 0.7. **(R 336.1707(2)(a))**
- b. The solvent bath must be covered with water if the solvent is insoluble and has a specific gravity of more than 1.0. **(R 336.1707(2)(b))**
- c. The cold cleaner must be controlled by a carbon adsorption system, condensation system, or other method of equivalent control approved by the AQD. **(R 336.1707(2)(c))**

V. TESTING/SAMPLING

NA

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. For each new cold cleaner in which the solvent is heated, the solvent temperature shall be monitored and recorded at least once each calendar week during routine operating conditions. **(R 336.1213(3))**
2. The permittee shall maintain the following information on file for each cold cleaner: **(R 336.1213(3))**
 - a. A serial number, model number, or other unique identifier for each cold cleaner.
 - b. The date the unit was installed, manufactured or that it commenced operation.
 - c. The air/vapor interface area for any unit claimed to be exempt under Rule 281(2)(h).
 - d. The applicable Rule 201 exemption.
 - e. The Reid vapor pressure of each solvent used.
 - f. If applicable, the option chosen to comply with Rule 707(2).
3. The permittee shall maintain written operating procedures for each cold cleaner. These written procedures shall be posted in an accessible, conspicuous location near each cold cleaner. **(R 336.1611(3), R 336.1707(4))**
4. As noted in Rule 611(2)(c) and Rule 707(3)(c), if applicable, an initial demonstration that the waste solvent is a safety hazard shall be made prior to storage in non-closed containers. If the waste solvent is a safety hazard and is stored in non-closed containers, verification that the waste solvent is disposed of so that not more than 20%, by weight, is allowed to evaporate into the atmosphere shall be made on a monthly basis. **(R 336.1213(3), R 336.1611(2)(c), R 336.1707(3)(c))**

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**
2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**
3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

NA

E. NON-APPLICABLE REQUIREMENTS

At the time of the ROP issuance, the AQD has determined that no non-applicable requirements have been identified for incorporation into the permit shield provision set forth in the General Conditions in Part A pursuant to Rule 213(6)(a)(ii).

APPENDICES

Appendix 1-A. Acronyms and Abbreviations

Common Acronyms		Pollutant / Measurement Abbreviations	
AQD	Air Quality Division	acfm	Actual cubic feet per minute
BACT	Best Available Control Technology	BTU	British Thermal Unit
CAA	Clean Air Act	°C	Degrees Celsius
CAM	Compliance Assurance Monitoring	CO	Carbon Monoxide
CEM	Continuous Emission Monitoring	CO ₂ e	Carbon Dioxide Equivalent
CEMS	Continuous Emission Monitoring System	dscf	Dry standard cubic foot
CFR	Code of Federal Regulations	dscm	Dry standard cubic meter
COM	Continuous Opacity Monitoring	°F	Degrees Fahrenheit
Department/ department	Michigan Department of Environment, Great Lakes, and Energy	gr	Grains
EGLE	Michigan Department of Environment, Great Lakes, and Energy	HAP	Hazardous Air Pollutant
EU	Emission Unit	Hg	Mercury
FG	Flexible Group	hr	Hour
GACS	Gallons of Applied Coating Solids	HP	Horsepower
GC	General Condition	H ₂ S	Hydrogen Sulfide
GHGs	Greenhouse Gases	kW	Kilowatt
HVLP	High Volume Low Pressure*	lb	Pound
ID	Identification	m	Meter
IRSL	Initial Risk Screening Level	mg	Milligram
ITSL	Initial Threshold Screening Level	mm	Millimeter
LAER	Lowest Achievable Emission Rate	MM	Million
MACT	Maximum Achievable Control Technology	MW	Megawatts
MAERS	Michigan Air Emissions Reporting System	NMOC	Non-methane Organic Compounds
MAP	Malfunction Abatement Plan	NO _x	Oxides of Nitrogen
MSDS	Material Safety Data Sheet	ng	Nanogram
NA	Not Applicable	PM	Particulate Matter
NAAQS	National Ambient Air Quality Standards	PM ₁₀	Particulate Matter equal to or less than 10 microns in diameter
NESHAP	National Emission Standard for Hazardous Air Pollutants	PM _{2.5}	Particulate Matter equal to or less than 2.5 microns in diameter
NSPS	New Source Performance Standards	pph	Pounds per hour
NSR	New Source Review	ppm	Parts per million
PS	Performance Specification	ppmv	Parts per million by volume
PSD	Prevention of Significant Deterioration	ppmw	Parts per million by weight
PTE	Permanent Total Enclosure	%	Percent
PTI	Permit to Install	psia	Pounds per square inch absolute
RACT	Reasonable Available Control Technology	psig	Pounds per square inch gauge
ROP	Renewable Operating Permit	scf	Standard cubic feet
SC	Special Condition	sec	Seconds
SCR	Selective Catalytic Reduction	SO ₂	Sulfur Dioxide
SNCR	Selective Non-Catalytic Reduction	TAC	Toxic Air Contaminant
SRN	State Registration Number	Temp	Temperature
TEQ	Toxicity Equivalence Quotient	THC	Total Hydrocarbons
USEPA/EPA	United States Environmental Protection Agency	tpy	Tons per year
VE	Visible Emissions	µg	Microgram
		µm	Micrometer or Micron
		VOC	Volatile Organic Compounds
		yr	Year

*For HVLP applicators, the pressure measured at the gun air cap shall not exceed 10 psig.

Appendix 1-B. Definitions Related to the Consent Agreement.

The following definitions apply to permit conditions originally established in the consent decree settling, “U.S. v Consumers Energy Company, Civil Action No. 14-13580, E.D. Mich., 2014.” This Appendix is also federally enforceable pursuant to Section 324.5503(b) of the Natural Resources and Environmental Protection Act, 1994 Act 451, as amended, Rule 201(1)(a), and Rule 214a, and will remain in effect after termination of the consent decree. **(Act 451, Section 324.5503(b))**

- For the purposes of the Consent Decree, every term expressly defined by this Appendix shall have the meaning given that term herein. Every other term used in the Consent Decree that is also a term used under the Act or in a federal regulation implementing the Act shall mean in the Consent Decree what such term means under the Act or those regulations. **(“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 4)**
- A "30-Day Rolling Average Emission Rate" for a Unit shall be expressed in lb/MMBTU and calculated in accordance with the following procedure: first, sum the total pounds of NO_x or SO₂ emitted from the Unit during the current Unit Operating Day and the previous 29 Unit Operating Days; second, sum the total heat input to the Unit in MMBTU during the current Unit Operating Day and the previous 29 Unit Operating Days; and third, divide the total number of pounds of NO_x or SO₂ emitted during the 30 Unit Operating Days by the total heat input during the 30 Unit Operating Days. A new 30-Day Rolling Average Emission Rate shall be calculated for each new Unit Operating Day. Each 30-Day Rolling Average Emission Rate shall include all emissions that occur during all periods within any Unit Operating Day, including emissions from startup, shutdown, and malfunction. **(“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 5)**
- A "90-Day Rolling Average Emission Rate" for a Unit shall be expressed in lb/MMBTU and calculated in accordance with the following procedure: first, sum the total pounds of NO_x or SO₂ emitted from the Unit during the current Unit Operating Day and the previous 89 Unit Operating Days; second, sum the total heat input to the Unit in MMBTU during the current Unit Operating Day and the previous 89 Unit Operating Days; and third, divide the total number of pounds of NO_x or SO₂ emitted during the 90 Unit Operating Days by the total heat input during the 90 Unit Operating Days. A new 90-Day Rolling Average Emission Rate shall be calculated for each new Unit Operating Day. Each 90-Day Rolling Average Emission Rate shall include all emissions that occur during all periods within any Unit Operating Day, including emissions from startup, shutdown, and malfunction. **(“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 6)**
- A "365-Day Rolling Average Emission Rate" for a Unit shall be expressed in lb/MMBTU and calculated in accordance with the following procedure: first, sum the pounds of the pollutant in question emitted from the Unit during the most recent Unit Operating Day and the previous 364 Unit Operating Days; second, sum the total heat input to the Unit in MMBTU during the most recent Unit Operating Day and the previous 364 Unit Operating Days; and third, divide the total number of pounds of the pollutant emitted during the 365 Unit Operating Days by the total heat input during the 365 Unit Operating Days. A new 365-Day Rolling Average Emission Rate shall be calculated for each new Unit Operating Day. Each 365-Day Rolling Average Emission Rate shall include all emissions that occur during all periods of operation, including startup, shutdown, and malfunction. **(“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 7)**
- "Baghouse" means a full stream (fabric filter or membrane) particulate emissions control device. Full stream is defined as capturing the entire stream of exhaust gas with no concurrent by-pass. **(“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 8)**
- "Campbell" means Consumers' J.H. Campbell Generating Plant consisting of three electric utility steam-generating units designated as Unit 1 (260 MW), Unit 2 (360 MW), and Unit 3 (835 MW) and related equipment, located in West Olive, Ottawa County, Michigan. Campbell Unit 3 is co-owned by Consumers (approximately 93%) along with Wolverine Power Supply Cooperative and the Michigan Public Power Association. **(“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 10)**
- "CEMS" or "Continuous Emission Monitoring System," means, for obligations involving the monitoring of NO_x and SO₂ emissions under the Consent Decree, the devices defined in 40 CFR 72.2 and installed and

maintained as required by 40 CFR Part 75. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 12)**

- "Clean Air Act" or "CAA" or "Act" means the federal Clean Air Act, 42 U.S.C. §§ 7401-7671q, and its implementing regulations. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 13)**
- "Cobb" means, for purposes of the Consent Decree, Consumers' B.C. Cobb Generating Plant consisting of two electric utility steam-generating units designated as Unit 4 (160 MW) and Unit 5 (160 MW) and related equipment, located in Muskegon, Muskegon County, Michigan. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 14)**
- "Consent Decree" means Consent Decree ("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014") and its Appendices. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 15)**
- "Consumers" means Consumers Energy Company. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 16)**
- "Consumers System" means the Campbell, Cobb, Karn, Weadock, and Whiting facilities as defined herein. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 17)**
- "Continuously Operate" or "Continuous Operation" means that when a pollution control technology or combustion control is required to be used at a Unit pursuant to the Consent Decree (including, but not limited to, SCR, FGD, DSI, ESP, Baghouse, or Low NOx Combustion System), it shall be operated at all times that the Unit it serves is in operation, except the SCRs on Campbell Units 2 and 3 need not be operated during scheduled maintenance on the applicable Unit's Urea Based Ammonia System and consistent with the technological limitations, manufacturers' specifications, good engineering and maintenance practices (including Campbell Unit 2 and Unit 3 scheduled Urea Based Ammonia System outages), and good air pollution control practices for minimizing emissions (as defined in 40 CFR 60.11(d)), as applicable, for such equipment and the Unit. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 18)**
- "Date of Entry" means the date the Consent Decree was signed by the United States District Court Judge (i.e. November 4, 2014). (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 19)**
- "Day" means calendar day unless otherwise specified in the Consent Decree. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 21)**
- "Dry Sorbent Injection" or "DSI" means a process in which a sorbent is pneumatically injected into the ducting downstream of where the coal is combusted and flue gas is produced, and upstream of the PM Control Device. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 22)**
- "Electrostatic Precipitator" or "ESP" means a device for removing particulate matter from combustion gases by imparting an electric charge to the particles and then attracting them to a metal plate or screen of opposite charge before the combustion gases are exhausted to the atmosphere. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 23)**
- "Emission Rate" for a given pollutant means the number of pounds of that pollutant emitted per million British Thermal Units of heat input (lb/MMBTU), calculated in accordance with each applicable 30, 90 or 365-Day Rolling Average Emission Rate definition. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 24)**
- "Flue Gas Desulfurization System" or "FGD" means a pollution control device that employs flue gas desulfurization technology, including an absorber or absorbers utilizing lime or limestone, or a sodium based material, for the reduction of SO₂ emissions. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 27)**
- "Fossil Fuel" means any hydrocarbon fuel, including coal, petroleum coke, petroleum oil, or natural gas. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 29)**
- "Full Stream Operation" is defined as the design configuration of a control device such that it captures the

entire stream of exhaust gas with no concurrent by-pass. (**“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 30**)

- "Karn," for purposes of the Consent Decree, means Consumers' D.E. Karn Generating Plant consisting of two electric utility steam-generating units designated as Unit 1 (255 MW) and Unit 2 (260 MW) and related equipment, located in Essexville, Bay County, Michigan. Karn does not include the oil-fired electricity generating units designated as Karn Units 3 and 4, also located in Essexville, Bay County, Michigan. (**“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 34**)
- "Karn Units 3 and 4" means Consumers' oil-fired Units 3 and 4, in Essexville, Bay County, Michigan. (**“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 35**)
- "KW" means Kilowatt or one thousand watts net. (**“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 36**)
- "lb/MMBTU" means one pound per million British Thermal Units. (**“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 37**)
- "Low NO_x Combustion System" means burners and associated combustion air control equipment, including Over Fire Air if specified, which control mixing characteristics of Fossil Fuel and oxygen, thus restraining the formation of NO_x during combustion of fuel in the boiler. (**“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 38**)
- "Malfunction" means a failure to operate in a normal or usual manner by any air pollution control equipment, process equipment, or a process, which is sudden, infrequent, and not reasonably preventable. Failures that are caused in part by poor maintenance or careless operation are not malfunctions. (**“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 39**)
- "Michigan SIP" means the Michigan State Implementation Plan, and any amendments thereto, as approved by USEPA pursuant to Section 110 of the Act, 42 U.S.C. § 7410. (**“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 40**)
- "MW" means a megawatt or one million watts net. (**“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 41**)
- "NO_x" means oxides of nitrogen, measured in accordance with the provisions of the Consent Decree. (**“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 45**)
- "NO_x Allowance" means an authorization to emit a specified amount of NO_x that is allocated or issued under an emissions trading or marketable permit program of any kind established under the Clean Air Act or the Michigan SIP; provided, however, that with respect to any such program that first applies to emissions occurring after December 31, 2011, a "NO_x Allowance" shall include an allowance created and allocated to a Consumers System Unit under such program only for control periods starting on or after November 4, 2018. (**“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 46**)
- "Operating Day" means any calendar day on which a Unit fires Fossil Fuel. (**“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 49**)
- "Over Fire Air" or "OFA" mean an in-furnace staged combustion control to reduce NO_x emissions. (**“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 51**)
- "PM" means total filterable particulate matter, measured in accordance with the provisions of the Consent Decree. (**“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 53**)
- "PM Continuous Emission Monitoring System" or "PM CEMS" means, for obligations involving the monitoring of PM emissions under the Consent Decree, the equipment that samples, analyzes, measures, and provides, by readings taken at frequent intervals, an electronic and/or paper record of PM emissions. (**“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 54**)
- "PM Control Device" means any device, including an ESP or Baghouse, which reduces emissions of PM. (**“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 55**)
- "PM Emission Rate" means the number of pounds of PM emitted per million BTU of heat input (lb/MMBTU). (**“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 56**)

- "Selective Catalytic Reduction" or "SCR" means an air pollution control device for reducing NO_x emissions in which ammonia ("NH₃") is added to the flue gas and then passed through layers of a catalyst material. The ammonia and NO_x in the flue gas stream react on the surface of the catalyst, forming nitrogen ("N₂") and water vapor. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 61**)
- "SO₂" means sulfur dioxide, measured in accordance with the provisions of the Consent Decree. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 62**)
- "SO₂ Allowance" means an authorization to emit a specified amount of SO₂ that is allocated or issued under an emissions trading or marketable permit program of any kind established under the Clean Air Act or the Michigan SIP; provided, however, that with respect to any such program that first applies to emissions occurring after December 31, 2011, an "SO₂ Allowance" shall include an allowance created and allocated to a Consumers System Unit under such program only for control periods starting on or after November 4, 2018. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 63**)
- "State" means the State of Michigan. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 64**)
- "State Implementation Plan" or "SIP" means regulations and other materials promulgated by a state for purposes of meeting the requirements of the Act that have been approved by USEPA pursuant to Section 110 of the Act, 42 U.S.C. § 7410. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 65**)
- "Surrender" or "Surrender of Allowances" means, for purposes of SO₂ or NO_x allowances, permanently surrendering allowances from the accounts administered by USEPA and Michigan for all Units in the Consumers System, so that such allowances can never be used thereafter to meet any compliance requirements under the Act, a SIP, or the Consent Decree. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 66**)
- "System-Wide Annual NO_x Tonnage Limitation" means the limitations, as specified in the Consent Decree, on the number of tons of NO_x that may be emitted from Campbell, Cobb, Kam, Weadock, and Whiting, collectively, during the relevant calendar year (i.e., January 1 through December 31), and shall include all emissions of NO_x during all periods of operations, including startup, shutdown, and malfunction. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 67**)
- "System-Wide Annual SO₂ Tonnage Limitation" means the limitations, as specified in the Consent Decree, on the number of tons of SO₂ that may be emitted from Campbell, Cobb, Kam, Weadock, and Whiting, collectively, during the relevant calendar year (i.e., January 1 through December 31), and shall include all emissions of SO₂ during all periods of operations, including startup, shutdown, and malfunction. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 68**)
- "Title V Permit" means the permit required of Consumers' major sources pursuant to Subchapter V of the Act, 42 U.S.C. §§ 7661-7661e. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 69**)
- "Unit" means collectively, the coal pulverizer, stationary equipment that feeds coal to the boiler, the boiler that produces steam for the steam turbine, the steam turbine, the generator, the equipment necessary to operate the generator, steam turbine, and boiler, and all ancillary equipment, including pollution control equipment and systems necessary for production of electricity. An electric steam generating station may comprise one or more Units. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 70**)
- "Urea Based Ammonia System" or "UBAS" means a type of ammonia feed system for SCRs where solid urea pellets are stored in a silo. Upon use, the solid urea is heated to liquid, thermally decomposed to ammonia, and injected into the SCR as the reagent for the NO_x reduction reaction. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 71**)
- "Weadock" means, for purposes of the Consent Decree, Consumers' J.C. Weadock Generating Plant consisting of two electric utility steam-generating Units designated as Unit 7 (155 MW) and Unit 8 (155 MW) and related equipment, located in Essexville, Bay County, Michigan. (**"U.S. v Consumers Energy**

Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 72)

- "Whiting" means, for purposes of the Consent Decree, Consumers' Whiting Generation Station consisting of three electric utility steam-generating Units designated as Unit 1 (102 MW), Unit 2 (102 MW), and Unit 3 (124 MW) and related equipment, located in Luna Pier, Monroe County, Michigan. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 73)**

Appendix 2. Schedule of Compliance

The permittee certified in the ROP application that this stationary source is in compliance with all applicable requirements and the permittee shall continue to comply with all terms and conditions of this ROP. A Schedule of Compliance is not required. (**R 336.1213(4)(a), R 336.1119(a)(ii)**)

Appendix 3. Monitoring Requirements

Appendix 3-A. Continuous Opacity Monitoring Systems

(This section applies to each boiler.)

The Continuous Opacity Monitoring System (COMS) performance specifications defined in 40 CFR Part 60, Appendix B, are adopted.

Cycling time for opacity: complete a minimum of one cycle of sampling/analysis for each successive 10-second period and one cycle of data recording for each successive 6-minute period. (**R 336.2152**)

Zero and Drift: The COMS must be subject to the manufacturer's zero and span check at least once daily. (**R 336.2153**)

Location: The location of the COMS or the monitoring devices must be such that representative measurement of emissions or process parameters are obtained. (**R 336.2155**)

Alternative Systems: AQD may approve the use of an alternative monitoring system if one is available that meets COMS objectives and if, because of physical limitations or other reasons, COMS cannot be installed or give accurate measurements. (**R 336.2159**)

Monitoring and reporting requirements shall not apply during any period of monitoring system malfunction if it can be demonstrated to the satisfaction of AQD that: the cause of the malfunction could not have been avoided by any reasonable action and necessary repairs are being made as expeditiously as practicable. (**R 336.2190**)

Appendix 3-B. Continuous Emissions Monitoring System (Title IV; Gas Flow, SO₂, CO₂, NO_x)

(This section applies to each boiler.)

The CEMS performance specifications defined in 40 CFR Part 75, Appendix B, are adopted.

Methods of measurement, frequency of measurement and recordkeeping methods for CEMS required under 40 CFR 75 are outlined in the most recent version of the Acid Rain Program - J. H. Campbell Plant Monitoring Plan, originally dated July 19, 1993.

Data Reporting: the AQD may approve alternative data reporting or reduction procedures if it can be demonstrated that such procedures are at least as accurate as the procedures identified in R 336.2175.

Appendix 3-C. Fuel Oil Sulfur Monitoring

Maintain a complete record of fuel oil specifications and/or a fuel analysis for each delivery, or storage tank, of fuel oil. These records may include purchase records for ASTM specification fuel oil, specifications or analyses provided by the vendor at the time of delivery, analytical results from laboratory testing, or any other records adequate to demonstrate compliance with the percent sulfur limit in fuel oil.

Appendix 3-D. Continuous Emission Monitoring Systems (SO₂/CO₂)

(This section applies to Units 1 and 2.)

The Continuous Emissions Monitoring Systems (CEMS) performance specifications defined in 40 CFR Part 75, Appendix B, are adopted. The Certified SO₂ and CO₂ monitors will be used to determine sulfur dioxide emissions. The data reduction procedures defined in R 336.2175 will be used to determine SO₂ lbs/MMBTU. On the last day of each calendar month, the CEMS data recording system will generate and record an "operating monthly average" as the average of the previous 31 operating days.

Appendix 3-E. PM CEMS

This Appendix is federally enforceable and was established pursuant to Rule 201(1)(a). This Appendix was originally established in the consent decree settling, "U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" and also pursuant Section 324.5503(b) of the Natural Resources and Environmental Protection Act, 1994 Act 451, as amended, and will remain in effect after termination of the consent decree. Definitions specific to this Appendix may be found in Appendix 1-B: Definitions. **(Act 451, Section 324.5503(b))**

- Consumers shall install, correlate, maintain, and operate a PM CEMS on Campbell Unit 3 as specified below. The PM CEMS shall comprise a continuous particle mass monitor measuring particulate matter concentration, directly or indirectly, on an hourly average basis and a diluent monitor used to convert the concentration to units expressed in lb/MMBTU. The PM CEMS installed must be appropriate for the anticipated stack conditions and capable of measuring PM concentrations on an hourly average basis. Consumers shall maintain, in an electronic database, the hourly average emission values of the PM CEMS in lb/MMBTU. Except for periods of monitor malfunction, maintenance, calibration, or repair, Consumers shall continuously operate the PM CEMS at all times when the Unit it serves is operating. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 159)**
- In developing both the plan for installation and correlation of the PM CEMS and the QA/QC protocol, Consumers shall use the criteria set forth in 40 CFR Part 60, Appendix B, Performance Specification 11, and Appendix F, Procedure 2. Following USEPA's approval of the plan described in Paragraph 160 of the Consent Decree and the QA/QC protocol described in Paragraph 161 of the Consent Decree, Consumers shall thereafter operate the PM CEMS in accordance with the approved plan and QA/QC protocol. Notwithstanding any other provision of the Consent Decree, exceedances of the PM Emission Rate that occur as a result of de-optimizing emission controls and/or spiking the exhaust gas with excess particulate required to achieve the high level PM test runs during the correlation testing shall not be a violation of the requirements of the Consent Decree (or credible evidence thereof); provided, however, that Consumers shall make best efforts to keep the high level PM test runs during such correlation testing below the applicable PM Emission Rate. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 162)**
- Consumers shall, correlate, maintain, and commence Continuous Operation of the PM CEMS approved by EGLE at Campbell Unit 3, conduct performance specification tests on the PM CEMS, and demonstrate compliance with the PM CEMS installation and correlation plans submitted to and approved by EGLE. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 163)**
- Except as approved pursuant to Paragraph 157 of the Consent Decree, stack testing shall be used to determine compliance with the PM Emission Rates established by the Consent Decree. Data from PM

CEMS shall be used, at a minimum, to provide information to operators on PM emissions rate trends on a continuous basis. (**“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 164**)

- The data recorded by the PM CEMS shall be expressed in lb/MMBTU on a rolling average 3-hour basis to identify any PM emission rates in excess of the applicable PM Emission Rate and shall be available in electronic format. (**U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 163**)

Appendix 3-F. Optimization of Baghouses

This Appendix is federally enforceable and was established pursuant to Rule 201(1)(a). This Appendix was originally established in the consent decree settling, “U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” and also pursuant Section 324.5503(b) of the Natural Resources and Environmental Protection Act, 1994 Act 451, as amended, and will remain in effect after termination of the consent decree. Definitions specific to this Appendix may be found in Appendix 1-B: Definitions. (**Act 451, Section 324.5503(b)**)

Consumers shall:

- a) At a minimum, to the extent practicable: (i) operate each compartment of the Baghouse as designed for Full Stream Operation for each Unit, where applicable (regardless of whether those actions are needed to comply with opacity limits); (ii) maintain and replace bags on each Baghouse as needed to maximize collection efficiency, where applicable; and
- b) During the next planned Unit outage (or unplanned outage of sufficient length), optimize the PM controls on that Unit by inspecting for and repairing any failed Baghouse compartment.

The above requirements are found in **“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 141.**

Appendix 4. Recordkeeping

Specific recordkeeping requirement formats and procedures are detailed in Part A or the appropriate Source-Wide, Emission Unit and/or Flexible Group Special Conditions. Therefore, this appendix is not applicable.

Appendix 5. Testing Procedures

This Appendix is federally enforceable and was established pursuant to Rule 201(1)(a). This Appendix was originally established in the consent decree settling, “U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” and also pursuant Section 324.5503(b) of the Natural Resources and Environmental Protection Act, 1994 Act 451, as amended, and will remain in effect after termination of the consent decree. Definitions specific to this Appendix may be found in Appendix 1-B: Definitions. (**Act 451, Section 324.5503(b)**)

Specific testing requirement plans, procedures and averaging times are detailed in the appropriate Requirement Tables. Moreover, the permittee shall use the following approved test plans, procedures and averaging times to measure the pollutant emissions for the applicable requirements referenced in Table EUBOILER3 (see below). Alternative test plans, procedures, or averaging must be approved by the AQD District Supervisor.

Test Methods and Procedures for Boiler #3

In conducting the performance test as required in 40 CFR 60.8, the owner or operator shall use the reference methods, procedures and test methods in 40 CFR Part 60, Appendix A or other methods and procedures specified in Section 60.46(d), except as provided in Section 60.8(b).

1. Particulate Matter: Method 17 at a facility without wet flue gas desulfurization system and Method 5B shall be used after flue gas desulfurization system. Method 5 and MATS method 5 shall also be used.
2. Opacity: Method 9.

3. SO₂: Method 6C shall be in the same sample site selected for particulate sample. The emission rate correction factor, integrated sampling and analysis procedure of Method 3A shall be used to determine the O₂ or CO₂ concentration, and shall be taken simultaneously and in the same point as the SO₂ sample.
2. NO_x: Method 7E shall be in the same sample site selected for particulate sample. The emission rate correction factor, integrated sampling and analysis procedure of Method 3A shall be used to determine the O₂ or CO₂ concentration, and shall be taken simultaneously and in the same point as the NO_x sample.

PM Emissions Testing and Monitoring Requirements

- Annually unless a Unit is Retired or Refueled to Natural Gas, Consumers shall conduct a stack test for PM pursuant to Paragraph 154 of the Consent Decree. The annual performance test requirement imposed on Consumers by this paragraph may be satisfied by stack tests conducted by Consumers as may be required by other conditions in its ROP for any year that such stack tests are required. Consumers may perform testing every other year, rather than every year, provided that two of the most recently completed test results from tests conducted in accordance with the methods and procedures specified above demonstrate that the PM emissions are equal to or less than 0.010 lb/MMBTU. Consumers shall perform testing every year, rather than every other year, beginning in the year immediately following any test result demonstrating that the PM emissions are greater than 0.010 lb/MMBTU.. (“**U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014**” paragraph 153)
- To determine compliance with the PM Emission Rate established in Subsections VI.B (Unit-Specific PM Requirements at Campbell Units 1 and 2), Consumers shall use the applicable reference methods and procedures (filterable portion only) specified in its ROP and the Michigan SIP for Campbell Units 1 and 2. Each test shall consist of three separate runs performed under representative operating conditions not including periods of startup, shutdown, or malfunction. The sampling time for each run associated with a Unit controlled by a Baghouse shall be at least 120 minutes and the volume of each run shall be at least 1.70 dry standard cubic meters (60 dry standard cubic feet). Consumers shall calculate the PM Emission Rate from the stack test results in accordance with 40 CFR 60.8(f). The results of each PM stack test shall be submitted to EGLE within 60 Days of completion of each test. (“**U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014**” paragraph 154)
- As an alternative to the PM testing required in this Appendix (PM Emissions Testing and Monitoring Requirements; beginning at paragraph 153) of the Consent Decree, following the installation and operation of PM CEMS as required by Appendix 3-E (PM CEMS), Consumers, at its sole discretion, may seek USEPA approval pursuant to Section XIII (Review and Approval of Submittals; beginning at paragraph 193) of the Consent Decree to forego stack testing and instead demonstrate continuous compliance with an applicable filterable PM Emission Rate by using the PM CEMS data on a 3-hour rolling average basis. (“**U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014**” paragraph 157)

Note: JHC EUBOILER3 was approved by USEPA to use the PM CEMS alternative to testing per letter dated January 20, 2020 and mailed on February 3, 2020 this PM CEMS approval letter is available upon request.

Appendix 6. Permits to Install

The following table lists any PTIs issued or ROP revision applications received since the effective date of the previously issued ROP No. MI-ROP-B2835-2013. Those ROP revision applications that are being issued concurrently with this ROP renewal are identified by an asterisk (*). Those revision applications not listed with an asterisk were processed prior to this renewal.

Source-Wide PTI No MI-PTI-B2835-2013 is being reissued as Source-Wide PTI No. MI-PTI-B2835-2020b.

Permit to Install Number	ROP Revision Application Number	Description of Equipment or Change	Corresponding Emission Unit(s) or Flexible Group(s)
142-12	201500412	PTI No. 141-12 incorporated EUCATDIESEL12.	EUCATDIESEL12
18-15	201500412	Incorporated USEPA Consent Decree conditions and to bridge the conditions with PTI No. 39-15. It also incorporated updates to control equipment that had been installed.	EUBYPRODUCT EUACIU123 EUDSI_U12 UESDA_U3
39-15	201500061	Incorporated Conditions of the USEPA Consent Decree that states: "The following must be included in the permit: a schedule for all unit-specific, plant-specific, and system-specific performance, operational, maintenance, and control technology requirements established by this Consent Decree including, but not limited to, any (a) 30-Day, 90-Day and 365-Day Rolling Average Emission Rates, (b) System-Wide Annual NOx and SO2 Tonnage Limitations, (c) the requirements pertaining to the Surrender of NOx and SO2 Allowances, (d) PM Emission Rate and annual stack test requirements, and (e) PM CEMS monitoring requirements."	EUBOILER1 EUBOILER2 EUBOILER3 Appendices 1, 3, 5, 7, and 10
18-15A	201800102*	Ash and byproduct handling system that transports ash and byproduct from the plant to the disposal silos. Unit 3 System: • 2 Transfer tanks each with a built in filter separator • 5 Vacuum Exhausters – exhaust to the Unit 3 PJFF Inlet Unit 1 and 2 System: • 2 Transfer tanks each with a built in filter separator • 3 Vacuum Exhausters – normally discharge to the Unit 1 PJFF inlet except for times when the Unit 1 PJFF is unavailable Common: • 3 Disposal Silos (A, B & C) • Truck loading	EUBYPRODUCT

The following table lists the ROP amendments or modifications issued after the effective date of ROP No. MI-ROP-B2835-2020.

Permit to Install Number	ROP Revision Application Number - Issuance Date	Description of Equipment or Change	Corresponding Emission Unit(s) or Flexible Group(s)
50-20	202000099 / September 3, 2020	Incorporate PTI 50-20 into the ROP, which was to correct emission limits for the water pump EUWPDIESEL. The change was due to an incorrect emission limit cited from 40 CFR Part 60 Subpart IIII in the previous permit but the correct emission limit was	EUWPDIESEL EUTRNCNTRDIESEL FGNEWCIRICE

Permit to Install Number	ROP Revision Application Number - Issuance Date	Description of Equipment or Change	Corresponding Emission Unit(s) or Flexible Group(s)
		used in the permit review. This correction was considered administrative and not subject to New Source Review during permitting. Additionally, the company identified two other errors in their ROP. The errors were related to the other engine in the flexible group, EUTRNCNTRDIESEL, which was not originally permitted through a PTI but was grouped with the fire pump engine EUWPDIESEL in the ROP. These errors were related to what federal subpart was/was not applicable to that engine. It appears that EUTRNCNTRDIESEL was accidentally included in FGNEWCIRICE Special Condition III. 1 at same time that EUTRNCNTRDIESEL was accidentally excluded from FGNEWCIRICE Special Condition III. 2. These emission units were corrected in FGNEWCIRICE. PTI 50-20 was not required to go through the public participation process.	
39-15A	202100070 / July 1, 2021	Incorporate PTI No. 39-15A into the ROP, which was for administrative updates to permitted conditions to reflect the termination of a Consent Decree between the USEPA and Consumers Energy. PTI No. 39-15A previously allowed Boiler #1 and #2 to have individual stacks or meet certain requirements if using a shared stack. The option and associated requirements for having a shared stack are also removed during this minor modification. It should be noted that PTI No. 39-15A had some errors that were corrected during this Modification. During the last ROP Renewal, the Company requested that the conditions common to boilers 1 and 2 housed in FGBOILER12 be separated and put into their respective boiler emission unit. This was done with the exception of all of the CAM requirements being kept in FGBOILERS12. Additionally, a separate FGMATSU12 table was created to house all of the common MATS requirements for the boilers. All requirements for EDTA and citrosolve have been removed as the units no longer burn any waste. The Conditions related to FGBOILER12 were accidentally added back into PTI No. 39-15A as well in	EUBOILER1, EUBOILER2 EUBOILER3, EUBYPRODUCT, FGBOILER12 Appendices 1-B, 3, 5

Permit to Install Number	ROP Revision Application Number - Issuance Date	Description of Equipment or Change	Corresponding Emission Unit(s) or Flexible Group(s)
		the associated Emission Units, so the Conditions were duplicative. AQD removed the duplicative and obsolete Conditions that were present in PTI No. 39-15A during this minor modification. During the Company's review, the Company requested to clarify in Appendix 3-E. PM CEMS, PM specification tests will be sent in the future to EGLE. This change would also allow updates to the installation and correlation plans to be submitted to and approved by EGLE.	

Appendix 7. Emission Calculations

Determination of Unit Specific NO_x or SO₂ Mass Emissions for Those Units Where 40 CFR Part 75 NO_x or SO₂ Mass Emissions Are Measured at a Common Stack

This Appendix is federally enforceable and was established pursuant to Rule 201(1)(a). This Appendix was originally established in the consent decree settling, "U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" and also pursuant Section 324.5503(b) of the Natural Resources and Environmental Protection Act, 1994 Act 451, as amended, and will remain in effect after termination of the consent decree. Definitions specific to this Appendix may be found in Appendix 1-B: Definitions. **(Act 451, Section 324.5503(b))**

For J.H. Campbell Units 1 and 2, NO_x mass emission rates are monitored at the associated common stacks via the use of NO_x concentration and flow CEMS. In addition, each of the preceding individual units are equipped with duct-level NO_x and diluent (i.e., CO₂) concentration CEMS to permit the determination of unit specific NO_x lb/MMBTU emission rates. The following procedures shall be used to calculate unit level NO_x mass emission rates for purposes of conducting rolling average NO_x lb/MMBTU calculations. If Campbell Units EUBOILER1 and EUBOILER2 elect to install unit level SO₂ CEMS only in lieu of installing both unit level SO₂ CEMS and Flow CEMS, the same procedure shall be followed for calculating unit level SO₂ mass emissions except that the value of K in Paragraph c. shall equal 1.660 x 10⁻⁷ (lb/scf)/ppm.

- a. From 40 CFR Part 75, Appendix F, equation F-15 (already calculated and reported under Part 75), common stack heat input shall be calculated as follows:

$$HI = Q_w \times \frac{1}{F_c} \times \frac{\%CO_{2w}}{100}$$

Where,

- HI* = Common stack hourly heat input rate during unit operation, MMBTU/hr
Q_w = Hourly average volumetric flow rate during unit operation, wet basis, scfh
F_c = Carbon-based F-factor, listed in 40 CFR 75, Appendix A, Section 3.3.5 for each fuel, scf/MMBTU
% CO_{2w} = Hourly concentration of CO₂ during unit operation, percent CO₂

- b. From 40 CFR Part 75, Appendix F, Equation F-21a (already calculated and reported under Part 75), individual unit heat input shall be calculated as follows:

$$HI_i = HI_{CS} \times \frac{T_{CS}}{t_i} \times \left[\frac{MW_i \times t_i}{\sum_{i=1}^n MW_i \times t_i} \right]$$

Where,

HI_i = Heat input rate for a unit, MMBTU/hr
 HI_{CS} = Heat input rate at the common stack, MMBTU/hr
 MW_i = Gross electrical output, MWe
 t_c = Unit operating time, hour or fraction of an hour
 t_{CS} = Common stack or common pipe operating time, hour or fraction of an hour
 n = Total number of units using the common stack
 i = Designation of a particular unit

- c. From 40 CFR Part 75, Appendix F, Equation F-6 (already calculated and reported under Part 75), individual unit NO_x lb/MMBTU emission rates shall be calculated as follows:

$$E = K \times C_h \times F_c \times \frac{100}{\%CO_2}$$

Where,

E = Pollutant emission rate during unit operation, lb/MMBTU
 K = 1.194×10^{-7} for NO_x (lb/scj)/ppm
 C_h = Hourly average NO_x concentration during unit operation, ppm
 F_c = Carbon-based F-factor, listed in 40 CFR 75, Appendix A, Section 3.3.5 for each fuel, scf/MMBTU
 $\%CO_2$ = Hourly concentration of CO₂ during unit operation, percent CO₂

- d. To calculate unit level NO_x mass emissions in each operating hour (not calculated or reported under Part 75), the following calculation shall be performed:

$$E_{(NOx)h} = E \times HI_i$$

Where,

$E_{(NOx)h}$ = NO_x mass emission rate for hour "h", in lbs/hr
 E = Pollutant emission rate during unit operation, lb/MMBTU
 HI_i = Heat input rate for a unit, MMBTU/hr

$$M_{(NOx)h} = E_{(NOx)h} \times t_h$$

Where,

$M_{(NOx)h}$ = NO_x mass emissions for hour "h", lbs
 $E_{(NOx)h}$ = NO_x mass emission rate for hour "h", in lbs/hr
 t_h = Unit operating time for hour "h", in hours or fraction of an hour

- e. The preceding unit specific NO_x mass emissions data shall then be used in accordance with Paragraphs 5, 6, and 7 of the CD (refer to Appendix 1-B) to calculate 30-day rolling, 90-day rolling and 365-day rolling NO_x lb/MMBTU emission rates, respectively (as applicable).

Appendix 8. Reporting

A. Annual, Semiannual, and Deviation Certification Reporting

The permittee shall use the EGLE, AQD, Report Certification form (EQP 5736) and EGLE, AQD, Deviation Report form (EQP 5737) for the annual, semiannual and deviation certification reporting referenced in the Reporting Section of the Source-Wide, Emission Unit and/or Flexible Group Special Conditions. Alternative formats must meet the provisions of Rule 213(4)(c) and Rule 213(3)(c)(i), respectively, and be approved by the AQD District Supervisor.

B. Other Reporting

The permittee shall use the following approved formats and procedures for the reporting requirements referenced in. EUBOILER3, EUCOALHAND, FGMATS_U12, and FGMATS_U3. For other reporting requirements, specific reporting requirement formats and procedures are detailed in Part A or the appropriate Requirement Tables. Alternative formats must be approved by the AQD District Supervisor.

Standards of Performance for New Sources (NSPS) reporting requirements for EUBOILER3 and EUCOALHAND include, but are not necessarily limited to, the following:

Notification requirements per Section 60.7 of 40 CFR Part 60, Subpart A;

60.7(a)(1)	Notification of the date of construction or reconstruction of an affected facility is commenced, postmarked no later than 30 days after such date.
60.7(a)(2)	Notification of the date or anticipated date of the initial startup of an affected facility, postmarked not more than 60 nor less than 30 days prior to such date.
60.7(a)(3)	Notification of the actual date of initial startup of an affected facility, postmarked within 15 days after such date.
60.7(a)(4)	Notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in Section 60.14(e). This notice shall be postmarked 60 days (or as soon as practicable) before the change is commenced.

Notifications of reconstruction activities per Section 60.15 of 40 CFR, Part 60, Subpart A; and

60.15(d)	If an owner or operator of an existing facility proposes to replace components and the fixed capital cost of the new components exceeds 50% of the fixed capital cost that would be required to construct a comparable entirely new facility, notification of the proposed replacements, postmarked 60 days (or as soon as practicable) before the construction of the replacements is commenced.

Reporting requirements per 40 CFR Part 60, Subpart D.

Excess emission (EE) reports and monitoring system performance (MSP) reports shall be submitted every quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter. Each EE and MSP report shall include the information required in Section 60.7(c). Periods of excess emission and monitoring system downtime that shall be reported are defined as followed:

1. Opacity: EE are defined as any 6-minute period during which the average opacity of emissions exceeds 20% opacity, except that one 6-minute average per hour of up to 27% need not be reported.
2. SO₂: EE are defined as any 3-hour period during which the average emissions (arithmetic average of 3 contiguous one-hour periods) of SO₂ as measured by a CEMS exceeded the applicable standard under Section 60.43, per Section 60.45(g)(2).

3. NO_x: EE are defined as any 3-hour period during which the average emissions (arithmetic average of 3 contiguous one-hour periods) of NO_x as measured by a CEMS exceeded the applicable standard under Section 60.44, Section 60.45(g)(3).

Appendix 9. Acid Rain Permit

PHASE II ACID RAIN PERMIT Permit No. MI-AR-1710-2020

Permittee	Consumers Energy – J.H. Campbell Plant
Address	17000 Croswell, West Olive, MI
SRN	B2835
ORIS Code	1710
Issue Date	February 4, 2020
Effective	Issuance date of this facility's Renewable Operating Permit at the facility in accordance with 40 CFR 72.73.
Expiration	This permit shall expire when the facility's Renewable Operating Permit expires, in accordance with 40 CFR 72.73.
ROP No.	MI-ROP-B2835-2020

The Acid Rain Permit Contents

1. A statement of basis prepared by the Air Quality Division (AQD) containing:

References to statutory and regulatory authorities, and with comments, notes, and justification that apply to the source in general;
2. Terms and conditions including:

A table of sulfur dioxide allowances to be allocated during the term of the permit, if applicable, authorized by this permit during Phase II. Unless they are subject to Sections 405(g)(2) or (3) of the federal Clean Air Act, new units are not allocated allowances in 40 CFR Part 73 and must obtain allowances by other means (Section 403(e) of the federal Clean Air Act);

Comments, notes and justifications regarding permit decisions and changes made to the permit application forms during the review process, and any additional requirements; and,

Any applicable nitrogen oxides compliance plan. Unless they are coal fired utility units regulated pursuant to Sections 404, 405, or 409 of the federal Clean Air Act, new units are not subject to the acid rain nitrogen oxides requirements (40 CFR 76.1(a)).
3. The permit application that this source submitted, as corrected by the AQD. The owners and operators of the source must comply with the standard requirements and special provisions set forth in the application.

Statement of Basis

Statutory and Regulatory Authorities.

In accordance with the Natural Resources and Environmental Protection Act, 1994 PA 451 and Titles IV and V of the federal Clean Air Act, the Michigan Department of Environment, Great Lakes, and Energy, Air Quality Division (AQD), issues this permit pursuant to the provisions of R 336.1210 to R 336.1218, and R 336.1299(d).

For further information contact:

Mr. Brian Carley
Environmental Quality Specialist
Michigan Department of Environment, Great Lakes, and Energy
Air Quality Division, Jackson District Office
State Office Building, 4th Floor
301 East Louis B. Glick Highway
Jackson, Michigan 49201-1556
Telephone: 517-416-4631
Facsimile: 517-780-7855

There are no comments, notes and/or justification that apply to the source in general for this section.

Terms and Conditions:

Phase II Sulfur Dioxide Allowance Allocation and Nitrogen Oxides Requirements for each affected unit.

		2020	2021	2022	2023	2024
Unit 1	SO ₂ allowances	8113	8113	8113	8113	8113
	NOx Emission Limits	Pursuant to 40 CFR part 76, the State of Michigan Department of Environment, Great Lakes, and Energy, Air Quality Division approves a NOx standard emissions limitation compliance plan for unit 1. The NOx compliance plan is effective beginning 2017. Under the NOx compliance plan, this unit's annual average NOx emissions rate for each year, determined in accordance with 40 CFR part 75, shall not exceed the applicable emission limitation, under 40 CFR 76.7(a)(2), of 0.45 lb/MMBTU for Phase I tangentially fired boilers. In addition to the described NOx compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NOx compliance plan and requirements covering excess emissions.				

		2020	2021	2022	2023	2024
Unit 2	SO ₂ allowances	9702	9702	9702	9702	9702
	NOx Emission Limits	Pursuant to 40 CFR part 76, the State of Michigan Department of Environment, Great Lakes, and Energy, Air Quality Division approves a NOx standard emissions limitation compliance plan for unit 2. The NOx compliance plan is effective beginning 2017. Under the NOx compliance plan, this unit's annual average NOx emissions rate for each year, determined in accordance with 40 CFR part 75, shall not exceed the applicable emission limitation, under 40 CFR 76.7(a)(2), of 0.68 lb/MMBTU for cell burner boilers. In addition to the described NOx compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NOx compliance plan and requirements covering excess emissions.				

Terms and Conditions (cont.):

		2020	2021	2022	2023	2024
Unit 3	SO ₂ allowances	27529	27529	27529	27529	27529
	NOx Emission Limits	Pursuant to 40 CFR part 76, the State of Michigan Department of Environment, Great Lakes, and Energy, Air Quality Division approves a NOx standard emissions limitation compliance plan for unit 3. The NOx compliance plan is effective beginning 2017. Under the NOx compliance plan, this unit's annual average NOx emissions rate for each year, determined in accordance with 40 CFR part 75, shall not exceed the applicable emission limitation, under 40 CFR 76.7(a)(2), of 0.46 lb/MMBTU for Phase II dry bottom wall-fired boilers. In addition to the described NOx compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NOx compliance plan and requirements covering excess emissions.				

Comments, notes and justifications regarding permit decisions, and changes made to the permit application forms during the review process:

Permit Application: (attached)

Acid Rain Permit Application submitted February 27, 2018
Acid Rain NOx Compliance Plan submitted July 5, 2017



United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 11/30/2018

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ☐ new ☐ revised ☒ for ARP permit renewal

STEP 1

Identify the facility name,
State, and plant (ORIS) code.

J.H. Campbell Plant Facility (Source) Name	MI State	1710 Plant Code

STEP 2

Enter the unit ID# for every
affected unit at the affected
source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
Unit 1	Yes
Unit 2	Yes
Unit 3	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

J.H. Campbell Plant
Facility (Source) Name (from STEP 1)

Acid Rain - Page 2

STEP 3

Read the standard requirements.

Permit Requirements

- (1) The designated representative of each affected source and each affected unit at the source shall:
 - (i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and
 - (ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;
- (2) The owners and operators of each affected source and each affected unit at the source shall:
 - (i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and
 - (ii) Have an Acid Rain Permit.

Monitoring Requirements

- (1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.
- (2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
- (3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

- (1) The owners and operators of each source and each affected unit at the source shall:
 - (i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and
 - (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
- (2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
- (3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
 - (i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or
 - (ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).
- (4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
- (5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
- (6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
- (7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

J.H. Campbell Plant
Facility (Source) Name (from STEP 1)

Acid Rain - Page 3

STEP 3, Cont'd.

Excess Emissions Requirements

- (1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
- (2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
 - (i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
 - (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

- (1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
 - (i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
 - (ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
 - (iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
 - (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
- (2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

- (1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
- (2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
- (3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
- (4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
- (5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
- (6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
- (7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

J.H. Campbell Plant
Facility (Source) Name (from STEP 1)

Acid Rain - Page 4

STEP 3, Cont'd.

Effect on Other Authorities

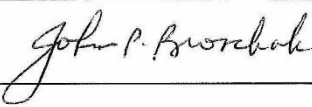
No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:

- (1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;
- (2) Limiting the number of allowances a source can hold; *provided*, that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;
- (3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;
- (4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
- (5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4
Read the
certification
statement, sign,
and date.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

John P. Broschak, Designated Representative	
Name	
Signature 	Date 1-24-18



United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 11/30/2018

Acid Rain NO_x Compliance Plan

For more information, see instructions and refer to 40 CFR 76.9

Page 1

This submission is: ☐ New ☒ Revised

Page 1 of 1

STEP 1

Indicate plant name, State, and Plant code from the current Certificate of Representation covering the facility.

Plant Name J.H. Campbell	State MI	Plant Code 1710

STEP 2

Identify each affected Group 1 and Group 2 boiler using the unit IDs from the current Certificate of Representation covering the facility. Also indicate the boiler type: "CB" for cell burner, "CY" for cyclone, "DBW" for dry bottom wall-fired, "T" for tangentially fired, "V" for vertically fired, and "WB" for wet bottom, and select the compliance option for each unit by making an 'X' in the appropriate row and column.

	ID# 1	ID# 2	ID# 3	ID#	ID#	ID#
	Type T	Type CB	Type DBW	Type	Type	Type
(a) Standard annual average emission limitation of 0.50 lb/mmBtu (for Phase I dry bottom wall-fired boilers)						
(b) Standard annual average emission limitation of 0.45 lb/mmBtu (for Phase I tangentially fired boilers)	X					
(c) Standard annual average emission limitation of 0.46 lb/mmBtu (for Phase II dry bottom wall-fired boilers)			X			
(d) Standard annual average emission limitation of 0.40 lb/mmBtu (for Phase II tangentially fired boilers)						
(e) Standard annual average emission limitation of 0.68 lb/mmBtu (for cell burner boilers)		X				
(f) Standard annual average emission limitation of 0.86 lb/mmBtu (for cyclone boilers)						
(g) Standard annual average emission limitation of 0.80 lb/mmBtu (for vertically fired boilers)						
(h) Standard annual average emission limitation of 0.84 lb/mmBtu (for wet bottom boilers)						
(i) NO _x Averaging Plan (include NO _x Averaging form)						
(j) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(A) (check the standard emission limitation box above for most stringent limitation applicable to any unit utilizing stack)						
(k) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(B) with NO _x Averaging (check the NO _x Averaging Plan box and include NO _x Averaging Form)						
(l) EPA-approved common stack apportionment method pursuant to 40 CFR 75.17(a)(2)(i)(C), (a)(2)(iii)(B), or (b)(2)						

J.H. Campbell
Plant Name (from Step 1)

NO_x Compliance - Page 2
Page 1 of 1

STEP 3
Identify the first calendar year in which this plan will apply.

January 1, 2017

STEP 4
Read the special provisions and certification, enter the name of the designated representative, sign and date.

Special Provisions

General.

This source is subject to the standard requirements in 40 CFR 72.9. These requirements are listed in this source's Acid Rain Permit.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name **John P. Broschak**

Signature

John P. Broschak

Date 6/29/17

Appendix 10: Cross State Air Pollution Rule (CSAPR) Trading Program Title V Requirements

Description of CSAPR Monitoring Provisions

The CSAPR subject units, and the unit-specific monitoring provisions, at this source are identified in the following tables. These units are subject to the requirements for the CSAPR NO_x Annual Trading Program, CSAPR NO_x Ozone Season Group 2 Trading Program, and CSAPR SO₂ Group 1 Trading Program, which are included below as Sections I, II, and III, respectively.

Each unit will use one of the following as the monitoring methodology for each parameter as provided below and shall comply with the general monitoring, recordkeeping, reporting and other requirements in conditions 1 through 5 below and in paragraph (b) of Sections I, II, and III:

- Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart B (for SO₂ monitoring) or 40 CFR Part 75, Subpart H (for NO_x monitoring)
- Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR Part 75, Appendix D
- Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR Part 75, Appendix E
- Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19
- USEPA-approved alternative monitoring system requirements pursuant to 40 CFR Part 75, Subpart E

Unit ID: 1	
Parameter	Monitoring Methodology
SO ₂	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart B
NO _x	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart H
Heat Input	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart B (for SO ₂ monitoring) or 40 CFR Part 75, Subpart H (for NO _x monitoring)

Unit ID: 2	
Parameter	Monitoring Methodology
SO ₂	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart B
NO _x	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart H
Heat Input	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart B (for SO ₂ monitoring) or 40 CFR Part 75, Subpart H (for NO _x monitoring)

Unit ID: 3	
Parameter	Monitoring Methodology
SO ₂	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart B
NO _x	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart H
Heat Input	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart B (for SO ₂ monitoring) or 40 CFR Part 75, Subpart H (for NO _x monitoring)

1. The above description of the monitoring used by a unit does not change, create an exemption from, or otherwise affect the monitoring, recordkeeping, and reporting requirements applicable to the unit under 40 CFR 97.430 through 97.435 (CSAPR NO_x Annual Trading Program), 97.830 through 97.835 (CSAPR NO_x Ozone Season Group 2 Trading Program), and 97.630 through 97.635 (CSAPR SO₂ Group 1 Trading Program). The monitoring, recordkeeping and reporting requirements applicable to each unit are included below in the standard conditions for the applicable CSAPR trading programs.

2. Owners and operators must submit to the Administrator a monitoring plan for each unit in accordance with 40 CFR 75.53, 75.62 and 75.73, as applicable. The monitoring plan for each unit is available at the USEPA's website at <https://www.epa.gov/airmarkets/clean-air-markets-monitoring-plans-part-75-sources>.
3. Owners and operators that want to use an alternative monitoring system must submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 CFR Part 75, Subpart E and 40 CFR 75.66 and 97.435 (CSAPR NO_x Annual Trading Program), 97.835 (CSAPR NO_x Ozone Season Group 2 Trading Program), and/or 97.635 (CSAPR SO₂ Group 1 Trading Program). The Administrator's response approving or disapproving any petition for an alternative monitoring system is available on the USEPA's website at <https://www.epa.gov/airmarkets/part-75-petition-responses>.
4. Owners and operators that want to use an alternative to any monitoring, recordkeeping, or reporting requirement under 40 CFR 97.430 through 97.434 (CSAPR NO_x Annual Trading Program), 97.830 through 97.834 (CSAPR NO_x Ozone Season Group 2 Trading Program), and/or 97.630 through 97.634 (CSAPR SO₂ Group 1 Trading Program) must submit to the Administrator a petition requesting approval of the alternative in accordance with 40 CFR 75.66 and 97.435 (CSAPR NO_x Annual Trading Program), 97.835 (CSAPR NO_x Ozone Season Group 2 Trading Program), and/or 97.635 (CSAPR SO₂ Group 1 Trading Program). The Administrator's response approving or disapproving any petition for an alternative to a monitoring, recordkeeping, or reporting requirement is available on the USEPA's website at <https://www.epa.gov/airmarkets/part-75-petition-responses>.
5. The descriptions of monitoring applicable to the unit included above meet the requirement of 40 CFR 97.430 through 97.434 (CSAPR NO_x Annual Trading Program), 97.830 through 97.834 (CSAPR NO_x Ozone Season Group 2 Trading Program), and 97.630 through 97.634 (CSAPR SO₂ Group 1 Trading Program), and therefore minor permit modification procedures, in accordance with 40 CFR 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B), may be used to add or change this unit's monitoring system description.

SECTION I: CSAPR NO_x Annual Trading Program requirements (40 CFR 97.406)

(a) Designated representative requirements.

The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.413 through 97.418.

(b) Emissions monitoring, reporting, and recordkeeping requirements.

- (1) The owners and operators, and the designated representative, of each CSAPR NO_x Annual source and each CSAPR NO_x Annual unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.430 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.431 (initial monitoring system certification and recertification procedures), 97.432 (monitoring system out-of-control periods), 97.433 (notifications concerning monitoring), 97.434 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.435 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).
- (2) The emissions data determined in accordance with 40 CFR 97.430 through 97.435 shall be used to calculate allocations of CSAPR NO_x Annual allowances under 40 CFR 97.411(a)(2) and (b) and 97.412 and to determine compliance with the CSAPR NO_x Annual emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.430 through 97.435 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) NO_x emissions requirements.

- (1) CSAPR NO_x Annual emissions limitation.
 - (i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NO_x Annual source and each CSAPR NO_x Annual unit at the source shall hold, in the source's compliance account, CSAPR NO_x Annual allowances available for deduction for such control period under 40 CFR 97.424(a) in an amount not less than the tons of total NO_x emissions for such control period from all CSAPR NO_x Annual units at the source.

- (ii). If total NO_x emissions during a control period in a given year from the CSAPR NO_x Annual units at a CSAPR NO_x Annual source are in excess of the CSAPR NO_x Annual emissions limitation set forth in paragraph (c)(1)(i) above, then:
 - (A). The owners and operators of the source and each CSAPR NO_x Annual unit at the source shall hold the CSAPR NO_x Annual allowances required for deduction under 40 CFR 97.424(d); and
 - (B). The owners and operators of the source and each CSAPR NO_x Annual unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR Part 97, Subpart AAAAA and the Clean Air Act.
- (2) CSAPR NO_x Annual assurance provisions.
 - (i). If total NO_x emissions during a control period in a given year from all CSAPR NO_x Annual units at CSAPR NO_x Annual sources in the state and Indian country within the borders of such State exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_x emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR NO_x Annual allowances available for deduction for such control period under 40 CFR 97.425(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.425(b), of multiplying— (A) The quotient of the amount by which the common designated representative's share of such NO_x emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state and Indian country within the borders of such state for such control period, by which each common designated representative's share of such NO_x emissions exceeds the respective common designated representative's assurance level; and (B) The amount by which total NO_x emissions from all CSAPR NO_x Annual units at CSAPR NO_x Annual sources in the state and Indian country within the borders of such state for such control period exceed the state assurance level.
 - (ii). The owners and operators shall hold the CSAPR NO_x Annual allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.
 - (iii). Total NO_x emissions from all CSAPR NO_x Annual units at CSAPR NO_x Annual sources in the State and Indian country within the borders of such state during a control period in a given year exceed the state assurance level if such total NO_x emissions exceed the sum, for such control period, of the state NO_x Annual trading budget under 40 CFR 97.410(a) and the state's variability limit under 40 CFR 97.410(b).
 - (iv). It shall not be a violation of 40 CFR Part 97, Subpart AAAAA or of the Clean Air Act if total NO_x emissions from all CSAPR NO_x Annual units at CSAPR NO_x Annual sources in the State and Indian country within the borders of such State during a control period exceed the state assurance level or if a common designated representative's share of total NO_x emissions from the CSAPR NO_x Annual units at CSAPR NO_x Annual sources in the state and Indian country within the borders of such state during a control period exceeds the common designated representative's assurance level.
 - (v). To the extent the owners and operators fail to hold CSAPR NO_x Annual allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,
 - (A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and
 - (B). Each CSAPR NO_x Annual allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR Part 97, Subpart AAAAA and the Clean Air Act.
- (3) Compliance periods.
 - (i). A CSAPR NO_x Annual unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of January 1, 2015, or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.

- (ii). A CSAPR NO_x Annual unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.
- (4) Vintage of allowances held for compliance.
 - (i). A CSAPR NO_x Annual allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a CSAPR NO_x Annual allowance that was allocated for such control period or a control period in a prior year.
 - (ii). A CSAPR NO_x Annual allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a CSAPR NO_x Annual allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.
- (5) Allowance Management System requirements. Each CSAPR NO_x Annual allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR Part 97, Subpart AAAAA.
- (6) Limited authorization. A CSAPR NO_x Annual allowance is a limited authorization to emit one ton of NO_x during the control period in one year. Such authorization is limited in its use and duration as follows:
 - (i). Such authorization shall only be used in accordance with the CSAPR NO_x Annual Trading Program; and
 - (ii). Notwithstanding any other provision of 40 CFR Part 97, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.
- (7) Property right. A CSAPR NO_x Annual allowance does not constitute a property right.

(d) Title V permit revision requirements.

- (1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR NO_x Annual allowances in accordance with 40 CFR Part 97, Subpart AAAAA.
- (2) This permit incorporates the CSAPR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.430 through 97.435, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR Part 75, Subparts B and H), an excepted monitoring system (pursuant to 40 CFR Part 75, Appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR Part 75, Subpart E). Therefore, the Description of CSAPR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.406(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

(e) Additional recordkeeping and reporting requirements.

- (1) Unless otherwise provided, the owners and operators of each CSAPR NO_x Annual source and each CSAPR NO_x Annual unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.
 - (i). The certificate of representation under 40 CFR 97.416 for the designated representative for the source and each CSAPR NO_x Annual unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.416 changing the designated representative.
 - (ii). All emissions monitoring information, in accordance with 40 CFR Part 97, Subpart AAAAA.
 - (iii). Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR NO_x Annual Trading Program.
- (2) The designated representative of a CSAPR NO_x Annual source and each CSAPR NO_x Annual unit at the source shall make all submissions required under the CSAPR NO_x Annual Trading Program, except as provided in 40 CFR 97.418. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR Parts 70 and 71.

(f) Liability.

- (1) Any provision of the CSAPR NO_x Annual Trading Program that applies to a CSAPR NO_x Annual source or the designated representative of a CSAPR NO_x Annual source shall also apply to the owners and operators of such source and of the CSAPR NO_x Annual units at the source.
- (2) Any provision of the CSAPR NO_x Annual Trading Program that applies to a CSAPR NO_x Annual unit or the designated representative of a CSAPR NO_x Annual unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities.

No provision of the CSAPR NO_x Annual Trading Program or exemption under 40 CFR 97.405 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR NO_x Annual source or CSAPR NO_x Annual unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

(h) Effect on units in Indian country.

Notwithstanding the provisions of paragraphs (a) through (g) above, paragraphs (a) through (g) shall be deemed not to impose any requirements on any source or unit, or any owner, operator, or designated representative with regard to any source or unit, in Indian country within the borders of the state.

SECTION II: CSAPR NO_x Ozone Season Group 2 Trading Program Requirements (40 CFR 97.806)

(a) Designated representative requirements.

The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.813 through 97.818.

(b) Emissions monitoring, reporting, and recordkeeping requirements.

- (1) The owners and operators, and the designated representative, of each CSAPR NO_x Ozone Season Group 2 source and each CSAPR NO_x Ozone Season Group 2 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.830 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.831 (initial monitoring system certification and recertification procedures), 97.832 (monitoring system out-of-control periods), 97.833 (notifications concerning monitoring), 97.834 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.835 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).
- (2) The emissions data determined in accordance with 40 CFR 97.830 through 97.835 shall be used to calculate allocations of CSAPR NO_x Ozone Season Group 2 allowances under 40 CFR 97.811(a)(2) and (b) and 97.812 and to determine compliance with the CSAPR NO_x Ozone Season Group 2 emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.830 through 97.835 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) NO_x emissions requirements.

- (1) CSAPR NO_x Ozone Season Group 2 emissions limitation.
 - (i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NO_x Ozone Season Group 2 source and each CSAPR NO_x Ozone Season Group 2 unit at the source shall hold, in the source's compliance account, CSAPR NO_x Ozone Season Group 2 allowances available for deduction for such control period under 40 CFR 97.824(a) in an amount not less than the tons of total NO_x emissions for such control period from all CSAPR NO_x Ozone Season Group 2 units at the source.
 - (ii). If total NO_x emissions during a control period in a given year from the CSAPR NO_x Ozone Season Group 2 units at a CSAPR NO_x Ozone Season Group 2 source are in excess of the CSAPR NO_x Ozone Season Group 2 emissions limitation set forth in paragraph (c)(1)(i) above, then:

- (A). The owners and operators of the source and each CSAPR NO_x Ozone Season Group 2 unit at the source shall hold the CSAPR NO_x Ozone Season Group 2 allowances required for deduction under 40 CFR 97.824(d); and
 - (B). The owners and operators of the source and each CSAPR NO_x Ozone Season Group 2 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR Part 97, Subpart EEEEE and the Clean Air Act.
- (2) CSAPR NO_x Ozone Season Group 2 assurance provisions.
- (i). If total NO_x emissions during a control period in a given year from all CSAPR NO_x Ozone Season Group 2 units at CSAPR NO_x Ozone Season Group 2 sources in the state and Indian country within the borders of such state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_x emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR NO_x Ozone Season Group 2 allowances available for deduction for such control period under 40 CFR 97.825(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.825(b), of multiplying—
 - (A). The quotient of the amount by which the common designated representative's share of such NO_x emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state and Indian country within the borders of such state for such control period, by which each common designated representative's share of such NO_x emissions exceeds the respective common designated representative's assurance level; and
 - (B). The amount by which total NO_x emissions from all CSAPR NO_x Ozone Season Group 2 units at CSAPR NO_x Ozone Season Group 2 sources in the state and Indian country within the borders of such state for such control period exceed the state assurance level.
 - (ii). The owners and operators shall hold the CSAPR NO_x Ozone Season Group 2 allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.
 - (iii). Total NO_x emissions from all CSAPR NO_x Ozone Season Group 2 units at CSAPR NO_x Ozone Season Group 2 sources in the state and Indian country within the borders of such state during a control period in a given year exceed the state assurance level if such total NO_x emissions exceed the sum, for such control period, of the State NO_x Ozone Season Group 2 trading budget under 40 CFR 97.810(a) and the state's variability limit under 40 CFR 97.810(b).
 - (iv). It shall not be a violation of 40 CFR Part 97, Subpart EEEEE or of the Clean Air Act if total NO_x emissions from all CSAPR NO_x Ozone Season Group 2 units at CSAPR NO_x Ozone Season Group 2 sources in the state and Indian country within the borders of such state during a control period exceed the state assurance level or if a common designated representative's share of total NO_x emissions from the CSAPR NO_x Ozone Season Group 2 units at CSAPR NO_x Ozone Season Group 2 sources in the state and Indian country within the borders of such state during a control period exceeds the common designated representative's assurance level.
 - (v). To the extent the owners and operators fail to hold CSAPR NO_x Ozone Season Group 2 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,
 - (A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and
 - (B). Each CSAPR NO_x Ozone Season Group 2 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR Part 97, Subpart EEEEE and the Clean Air Act.
- (3) Compliance periods.
- (i). A CSAPR NO_x Ozone Season Group 2 unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.830(b) and for each control period thereafter.

- (ii). A CSAPR NO_x Ozone Season Group 2 unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.830(b) and for each control period thereafter.
- (4) Vintage of allowances held for compliance.
 - (i). A CSAPR NO_x Ozone Season Group 2 allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a CSAPR NO_x Ozone Season Group 2 allowance that was allocated for such control period or a control period in a prior year.
 - (ii). A CSAPR NO_x Ozone Season Group 2 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a CSAPR NO_x Ozone Season Group 2 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.
- (5) Allowance Management System requirements. Each CSAPR NO_x Ozone Season Group 2 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR Part 97, Subpart EEEEE.
- (6) Limited authorization. A CSAPR NO_x Ozone Season Group 2 allowance is a limited authorization to emit one ton of NO_x during the control period in one year. Such authorization is limited in its use and duration as follows:
 - (i). Such authorization shall only be used in accordance with the CSAPR NO_x Ozone Season Group 2 Trading Program; and
 - (ii). Notwithstanding any other provision of 40 CFR Part 97, Subpart EEEEE, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.
- (7) Property right. A CSAPR NO_x Ozone Season Group 2 allowance does not constitute a property right.

(d) Title V permit revision requirements.

- (1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR NO_x Ozone Season Group 2 allowances in accordance with 40 CFR Part 97, Subpart EEEEE.
- (2) This permit incorporates the CSAPR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.830 through 97.835, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR Part 75, Subparts B and H), an excepted monitoring system (pursuant to 40 CFR Part 75, Appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR Part 75, Subpart E). Therefore, the Description of CSAPR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.806(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

(e) Additional recordkeeping and reporting requirements.

- (1) Unless otherwise provided, the owners and operators of each CSAPR NO_x Ozone Season Group 2 source and each CSAPR NO_x Ozone Season Group 2 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.
 - (i). The certificate of representation under 40 CFR 97.816 for the designated representative for the source and each CSAPR NO_x Ozone Season Group 2 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.816 changing the designated representative.
 - (ii). All emissions monitoring information, in accordance with 40 CFR Part 97, Subpart EEEEE.
 - (iii). Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR NO_x Ozone Season Group 2 Trading Program.
- (2) The designated representative of a CSAPR NO_x Ozone Season Group 2 source and each CSAPR NO_x Ozone Season Group 2 unit at the source shall make all submissions required under the CSAPR NO_x Ozone Season Group 2 Trading Program, except as provided in 40 CFR 97.818. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR Parts 70 and 71.

(f) Liability.

- (1) Any provision of the CSAPR NO_x Ozone Season Group 2 Trading Program that applies to a CSAPR NO_x Ozone Season Group 2 source or the designated representative of a CSAPR NO_x Ozone Season Group 2 source shall also apply to the owners and operators of such source and of the CSAPR NO_x Ozone Season Group 2 units at the source.
- (2) Any provision of the CSAPR NO_x Ozone Season Group 2 Trading Program that applies to a CSAPR NO_x Ozone Season Group 2 unit or the designated representative of a CSAPR NO_x Ozone Season Group 2 unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities.

No provision of the CSAPR NO_x Ozone Season Group 2 Trading Program or exemption under 40 CFR 97.805 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR NO_x Ozone Season Group 2 source or CSAPR NO_x Ozone Season Group 2 unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

(h) Effect on units in Indian country.

Notwithstanding the provisions of paragraphs (a) through (g) above, paragraphs (a) through (g) shall be deemed not to impose any requirements on any source or unit, or any owner, operator, or designated representative with regard to any source or unit, in Indian country within the borders of the state.

SECTION III: CSAPR SO₂ Group 1 Trading Program requirements (40 CFR 97.606)

(a) Designated representative requirements.

The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.613 through 97.618.

(b) Emissions monitoring, reporting, and recordkeeping requirements.

- (1) The owners and operators, and the designated representative, of each CSAPR SO₂ Group 1 source and each CSAPR SO₂ Group 1 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.630 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.631 (initial monitoring system certification and recertification procedures), 97.632 (monitoring system out-of-control periods), 97.633 (notifications concerning monitoring), 97.634 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.635 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).
- (2) The emissions data determined in accordance with 40 CFR 97.630 through 97.635 shall be used to calculate allocations of CSAPR SO₂ Group 1 allowances under 40 CFR 97.611(a)(2) and (b) and 97.612 and to determine compliance with the CSAPR SO₂ Group 1 emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.630 through 97.635 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) SO₂ emissions requirements.

- (1) CSAPR SO₂ Group 1 emissions limitation.
 - (i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR SO₂ Group 1 source and each CSAPR SO₂ Group 1 unit at the source shall hold, in the source's compliance account, CSAPR SO₂ Group 1 allowances available for deduction for such control period under 40 CFR 97.624(a) in an amount not less than the tons of total SO₂ emissions for such control period from all CSAPR SO₂ Group 1 units at the source.
 - (ii). If total SO₂ emissions during a control period in a given year from the CSAPR SO₂ Group 1 units at a CSAPR SO₂ Group 1 source are in excess of the CSAPR SO₂ Group 1 emissions limitation set forth in paragraph (c)(1)(i) above, then:

- (A). The owners and operators of the source and each CSAPR SO₂ Group 1 unit at the source shall hold the CSAPR SO₂ Group 1 allowances required for deduction under 40 CFR 97.624(d); and
 - (B). The owners and operators of the source and each CSAPR SO₂ Group 1 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation 40 CFR Part 97, Subpart CCCCC and the Clean Air Act.
- (2) CSAPR SO₂ Group 1 assurance provisions.
- (i). If total SO₂ emissions during a control period in a given year from all CSAPR SO₂ Group 1 units at CSAPR SO₂ Group 1 sources in the state and Indian country within the borders of such state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such SO₂ emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR SO₂ Group 1 allowances available for deduction for such control period under 40 CFR 97.625(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.625(b), of multiplying—
 - (A). The quotient of the amount by which the common designated representative's share of such SO₂ emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state and Indian country within the borders of such state for such control period, by which each common designated representative's share of such SO₂ emissions exceeds the respective common designated representative's assurance level; and
 - (B). The amount by which total SO₂ emissions from all CSAPR SO₂ Group 1 units at CSAPR SO₂ Group 1 sources in the state and Indian country within the borders of such state for such control period exceed the state assurance level.
 - (ii). The owners and operators shall hold the CSAPR SO₂ Group 1 allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.
 - (iii). Total SO₂ emissions from all CSAPR SO₂ Group 1 units at CSAPR SO₂ Group 1 sources in the state and Indian country within the borders of such state during a control period in a given year exceed the state assurance level if such total SO₂ emissions exceed the sum, for such control period, of the state SO₂ Group 1 trading budget under 40 CFR 97.610(a) and the state's variability limit under 40 CFR 97.610(b).
 - (iv). It shall not be a violation of 40 CFR Part 97, Subpart CCCCC or of the Clean Air Act if total SO₂ emissions from all CSAPR SO₂ Group 1 units at CSAPR SO₂ Group 1 sources in the state and Indian country within the borders of such state during a control period exceed the state assurance level or if a common designated representative's share of total SO₂ emissions from the CSAPR SO₂ Group 1 units at CSAPR SO₂ Group 1 sources in the state and Indian country within the borders of such state during a control period exceeds the common designated representative's assurance level.
 - (v). To the extent the owners and operators fail to hold CSAPR SO₂ Group 1 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,
 - (A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and
 - (B). Each CSAPR SO₂ Group 1 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR Part 97, Subpart CCCCC and the Clean Air Act.
- (3) Compliance periods.
- (i). A CSAPR SO₂ Group 1 unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of January 1, 2015 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.
 - (ii). A CSAPR SO₂ Group 1 unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.
- (4) Vintage of allowances held for compliance.

- (i). A CSAPR SO₂ Group 1 allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a CSAPR SO₂ Group 1 allowance that was allocated for such control period or a control period in a prior year.
- (ii). A CSAPR SO₂ Group 1 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a CSAPR SO₂ Group 1 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.
- (5) Allowance Management System requirements. Each CSAPR SO₂ Group 1 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR Part 97, Subpart CCCCC.
- (6) Limited authorization. A CSAPR SO₂ Group 1 allowance is a limited authorization to emit one ton of SO₂ during the control period in one year. Such authorization is limited in its use and duration as follows:
 - (i). Such authorization shall only be used in accordance with the CSAPR SO₂ Group 1 Trading Program; and
 - (ii). Notwithstanding any other provision of 40 CFR Part 97, Subpart CCCCC, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.
- (7) Property right. A CSAPR SO₂ Group 1 allowance does not constitute a property right.

(d) Title V permit revision requirements.

- (1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR SO₂ Group 1 allowances in accordance with 40 CFR Part 97, Subpart CCCCC.
- (2) This permit incorporates the CSAPR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.630 through 97.635, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR Part 75, Subparts B and H), an excepted monitoring system (pursuant to 40 CFR Part 75, Appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR Part 75, Subpart E). Therefore, the Description of CSAPR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.606(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

(e) Additional recordkeeping and reporting requirements.

- (1) Unless otherwise provided, the owners and operators of each CSAPR SO₂ Group 1 source and each CSAPR SO₂ Group 1 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.
 - (i). The certificate of representation under 40 CFR 97.616 for the designated representative for the source and each CSAPR SO₂ Group 1 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.616 changing the designated representative.
 - (ii). All emissions monitoring information, in accordance with 40 CFR Part 97, Subpart CCCCC.
 - (iii). Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR SO₂ Group 1 Trading Program.
- (2) The designated representative of a CSAPR SO₂ Group 1 source and each CSAPR SO₂ Group 1 unit at the source shall make all submissions required under the CSAPR SO₂ Group 1 Trading Program, except as provided in 40 CFR 97.618. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR Parts 70 and 71.

(f) Liability.

- (1) Any provision of the CSAPR SO₂ Group 1 Trading Program that applies to a CSAPR SO₂ Group 1 source or the designated representative of a CSAPR SO₂ Group 1 source shall also apply to the owners and operators of such source and of the CSAPR SO₂ Group 1 units at the source.

- (2) Any provision of the CSAPR SO₂ Group 1 Trading Program that applies to a CSAPR SO₂ Group 1 unit or the designated representative of a CSAPR SO₂ Group 1 unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities.

No provision of the CSAPR SO₂ Group 1 Trading Program or exemption under 40 CFR 97.605 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR SO₂ Group 1 source or CSAPR SO₂ Group 1 unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

(h) Effect on units in Indian country.

Notwithstanding the provisions of paragraphs (a) through (g) above, paragraphs (a) through (g) shall be deemed not to impose any requirements on any source or unit, or any owner, operator, or designated representative with regard to any source or unit, in Indian country within the borders of the state.

Appendix 11-A. System Wide Tonnage Limitations

This Appendix is federally enforceable and was established pursuant to Rule 201(1)(a). Appendix 11-A and Appendix 11-B were originally established in the consent decree settling, “U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” and also pursuant Section 324.5503(b) of the Natural Resources and Environmental Protection Act, 1994 Act 451, as amended, and will remain in effect after termination of the consent decree. Definitions specific to this Appendix may be found in Appendix 1-B: Definitions. **(Act 451, Section 324.5503(b))**

System-Wide Annual NO_x Tonnage Limitations

The Consumers System, collectively, shall operate so as not to exceed the following System-Wide Annual NO_x Tonnage Limitations:

For the Calendar Year Specified Below:	System-Wide Annual NO _x Tonnage Limitation:
2017 and continuing each calendar year thereafter	6,600

(“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 98)

- For purposes of calculating the System-Wide Annual NO_x Tonnage Limitations, Consumers shall use CEMS in accordance with the procedures specified in 40 CFR Part 75, which includes the requirements associated with the concepts of bias adjustments and missing data substitution. **(“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 100)**

System-Wide Annual SO₂ Tonnage Limitations

The Consumers System, collectively, shall operate so as not to exceed the following System-Wide Annual SO₂ Tonnage Limitations:

For the Calendar Year Specified Below:	System-Wide Annual SO ₂ Tonnage Limitation:
2017 and continuing each calendar year thereafter	10,900

(“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 129)

- For purposes of calculating the System-Wide Annual SO₂ Tonnage Limitations, Consumers shall use CEMS in accordance with the procedures specified in 40 CFR Part 75, which includes the requirements associated with the concepts of bias adjustments and missing data substitution. **(“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 131)**

Appendix 11-B. Allowance Provisions

This Appendix is federally enforceable and was established pursuant to Rule 201(1)(a). This Appendix was originally established in the consent decree settling, “U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” and also pursuant Section 324.5503(b) of the Natural Resources and Environmental Protection Act, 1994 Act 451, as amended, and will remain in effect after termination of the consent decree. Definitions specific to this Appendix may be found in Appendix 1-B: Definitions. **(Act 451, Section 324.5503(b))**

Use and Surrender of NOx Allowances

- Consumers shall not use NOx Allowances to comply with any requirement of the Consent Decree, as enumerated in this permit, including by claiming compliance with any emission limitation required by the Consent Decree, as provided in this permit, by using, tendering, or otherwise applying NOx Allowances to offset any excess emissions. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 101**)
- Except as provided by Appendix 11-B: Allowance Provisions, Consumers shall not sell, bank, trade, or transfer any NOx Allowances allocated to the Consumers System Units. Nothing in the Consent Decree shall restrict Consumers' ability to transfer NOx Allowances among its own facility or general accounts. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 102**)
- Beginning with the year 2014 compliance period, and continuing each year thereafter, Consumers shall Surrender all NOx Allowances allocated to the Consumers System for that year's compliance period that Consumers does not need in order to meet its own federal and/or state CAA regulatory requirements for the Consumers System Units. However, NOx Allowances allocated to the Consumers System may be used by Consumers to meet its own federal and/or state CAA regulatory requirements for such Units. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 103**)
- Nothing in Appendix 11-B: Allowance Provisions, shall prevent Consumers from purchasing or otherwise obtaining NOx Allowances from another source for purposes of complying with federal and/or state CAA regulatory requirements to the extent otherwise allowed by law. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 104**)

Super-Compliant NOx Allowances

- Beginning with the year 2014 and continuing in each calendar year thereafter, Consumers may sell, bank, use, trade, or transfer NOx Allowances made available in that year's compliance period solely as a result of:
 - a. the installation and operation of any NOx pollution control that is not otherwise required by, or necessary to maintain compliance with, any provision of the Consent Decree as provided in this permit, and is not otherwise required by law;
 - b. the use of SCR prior to the date established by the Consent Decree; or
 - c. achievement and maintenance of an Emission Rate below a 365-Day Rolling Average Emission Rate for NO_x at the following Units: (i) at Campbell Unit 1: 0.200 lb/MMBTU; (ii) at Campbell Unit 2: 0.070 lb/MMBTU; (iii) at Campbell Unit 3: 0.070 lb/MMBTU;provided that Consumers is also in compliance for that calendar year with all emission limitations for NO_x set forth in the Consent Decree as provided in this permit. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 106**)

Method for Surrender of NOx Allowances

- Consumers shall Surrender, or transfer to a non-profit third-party selected by Consumers for Surrender, all NOx Allowances required to be Surrendered pursuant to Appendix 11-B: Allowance Provisions by June 30 of the immediately following calendar year. Such Surrender need not include the specific NOx Allowances that were allocated to Consumers System Units, so long as Consumers Surrenders NO_x Allowances that are from the same year or an earlier year and that are equal to the number required to be Surrendered under the Consent Decree as provided in this permit. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 107**)
- If any NOx Allowances required to be Surrendered under Appendix 11-B: Allowance Provisions are transferred directly to a non-profit third-party, Consumers shall include a description of such transfer in the next report submitted to USEPA pursuant to the Periodic Reporting provisions of the Consent Decree (beginning at paragraph 188 of the Consent Decree). Such report shall: (a) identify the non-profit third-party recipient(s) of the NOx Allowances and list the serial numbers of the transferred NOx Allowances; and (b) include a certification by the third-party recipient(s) stating that the recipient(s) will not sell, trade, or otherwise exchange any of the NOx Allowances and will not use any of the NOx Allowances to meet any obligation imposed by any environmental law. No later than the third periodic report due after the transfer of any NOx Allowances, Consumers shall include a statement that the third-party recipient(s) Surrendered the NOx Allowances for permanent Surrender to USEPA in accordance with the provisions of Appendix 11-B, "Method for Surrender of NOx Allowances," within one year after Consumers transferred the NOx Allowances to them. Consumers shall not have complied with the NOx

Allowance Surrender requirements of Appendix 11-B, "Method for Surrender of NO_x Allowances," until all third-party recipient(s) have actually Surrendered the transferred NO_x Allowances to USEPA. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 108**)

- For all NO_x Allowances required to be Surrendered, Consumers or the third-party recipient(s) (as the case may be) shall first submit a NO_x Allowance transfer request to USEPA's Office of Air and Radiation's Clean Air Markets Division directing the transfer of such NO_x Allowances to the USEPA Enforcement Surrender Account or to any other USEPA account that USEPA may direct in writing. Such NO_x Allowance transfer requests may be made in an electronic manner using USEPA's Clean Air Markets Division Business System or similar system provided by USEPA. As part of submitting these transfer requests, Consumers or the third-party recipient(s) shall irrevocably authorize the transfer of these NO_x Allowances and identify – by name of account and any applicable serial or other identification numbers or station names – the source and location of the NO_x Allowances being Surrendered. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 109**)

Use and Surrender of SO₂ Allowances

- Consumers shall not use SO₂ Allowances to comply with any requirement of the Consent Decree, as enumerated in this permit, including by claiming compliance with any emission limitation required by the Consent Decree, as enumerated in this permit, by using, tendering, or otherwise applying SO₂ Allowances to offset any excess emissions. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 132**)
- Except as provided in Appendix 11-B: Allowance Provisions, Consumers shall not sell, bank, trade, or transfer any SO₂ Allowances allocated to the Consumers System Units. Nothing in Appendix 11-B: Allowance Provisions, shall restrict Consumers' ability to transfer SO₂ Allowances among its own facility or general accounts. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 133**)
- Beginning with the year 2014 compliance period, and continuing each year thereafter, Consumers shall Surrender all SO₂ Allowances allocated to the Consumers System for that year's compliance period that Consumers does not need in order to meet its own federal and/or state CAA regulatory requirements for the Consumers System Units. However, SO₂ Allowances allocated to the Consumers System Units may be used by Consumers to meet its own federal and/or state CAA regulatory requirements for such Units. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 134**)
- Nothing in Appendix 11-B: Allowance Provisions, shall prevent Consumers from purchasing or otherwise obtaining SO₂ Allowances from another source for purposes of complying with federal and/or state CAA regulatory requirements to the extent otherwise allowed by law. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 135**)

Super-Compliant SO₂ Allowances

- Beginning with the year 2014 and continuing in each calendar year thereafter, Consumers may sell, bank, use, trade, or transfer SO₂ Allowances made available in that year's compliance period solely as a result of:
 - a. the installation and operation of any SO₂ pollution control that is not otherwise required by, or necessary to maintain compliance with, any provision of the Consent Decree, and is not otherwise required by law;
 - b. the use of FGD or DSI prior to the date established by the Consent Decree; or
 - c. achievement and maintenance of an Emission Rate below a 365-Day Rolling Average Emission Rate for SO₂ at the following Units: (i) at Campbell Units 1 and 2: 0.260 lb/MMBTU; (ii) at Campbell Unit 3: 0.060 lb/MMBTUprovided that Consumers is also in compliance for that calendar year with all emission limitations for SO₂ set forth in the Consent Decree as provided in this permit. (**"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 137**)

Method for Surrender of SO₂ Allowances

- Consumers shall Surrender, or transfer to a non-profit third party selected by Consumers for Surrender, all SO₂ Allowances required to be Surrendered pursuant to Appendix 11-B: Allowance Provisions, by June 30 of the immediately following calendar year. Such Surrender need not include the specific SO₂ Allowances that were allocated to Consumers System Units, so long as Consumers Surrenders SO₂ Allowances that are from the same year or an earlier year and that are equal to the number required to be Surrendered under Appendix 11-B:

Allowance Provisions. (**“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 138**)

- If any SO₂ Allowances required to be Surrendered under Appendix 11-B, “Use and Surrender of SO₂ Allowances,” are transferred directly to a non-profit third party, Consumers shall include a description of such transfer in the next report submitted to USEPA pursuant to the Periodic Reporting provisions of the Consent Decree (beginning at paragraph 188 of the Consent Decree). Such report shall: (a) identify the non-profit third-party recipient(s) of the SO₂ Allowances and list the serial numbers of the transferred SO₂ Allowances; and (b) include a certification by the non-profit third-party recipient(s) stating that the recipient(s) will not sell, trade, or otherwise exchange any of the allowances and will not use any of the SO₂ Allowances to meet any obligation imposed by any environmental law. No later than the third periodic report due after the transfer of any SO₂ Allowances, Consumers shall include a statement that the non-profit third-party recipient(s) Surrendered the SO₂ Allowances for permanent Surrender to USEPA in accordance with the provisions of the following Paragraph 140 Appendix 11-B, “Method for Surrender of SO₂ Allowances,” within one year after Consumers transferred the SO₂ Allowances to them. Consumers shall not have complied with the SO₂ Allowance Surrender requirements of this Appendix 11-B, “Method for Surrender of SO₂ Allowances,” until all third-party recipient(s) have actually Surrendered the transferred SO₂ Allowances to USEPA. (**“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 139**)
- For all SO₂ Allowances required to be Surrendered, Consumers or the third-party recipient(s) (as the case may be) shall first submit an SO₂ Allowance transfer request to USEPA’s Office of Air and Radiation’s Clean Air Markets Division directing the transfer of such SO₂ Allowances to the USEPA Enforcement Surrender Account or to any other USEPA account that USEPA may direct in writing. Such SO₂ Allowance transfer requests may be made in an electronic manner using USEPA’s Clean Air Markets Division Business System or similar system provided by USEPA. As part of submitting these transfer requests, Consumers or the third-party recipient(s) shall irrevocably authorize the transfer of these SO₂ Allowances and identify – by name of account and any applicable serial or other identification numbers or station names – the source and location of the SO₂ Allowances being Surrendered. (**“U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014” paragraph 140**)

Attachment F

Case 21090 Kapala Direct Testimony

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief. 	))))))	Case No. U-21090

REVISED DIRECT TESTIMONY

OF

NORMAN J. KAPALA

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2021

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1 **Q. Please state your name and business address.**

2 A. My name is Norman J. Kapala, and my business address is One Energy Plaza, Jackson,
3 Michigan 49201.

4 **Q. By whom are you employed and in what capacity?**

5 A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”)
6 as Executive Director of Fossil and Renewable Generation.

7 **Q. What is your formal education experience?**

8 A. In 1996, I received a Bachelor of Science in Mechanical Engineering from Michigan
9 Technological University. In 2008, I received a Master of Science in Manufacturing
10 Management from Kettering University.

11 **Q. Please describe your business experience.**

12 A. From 1990 to 1994, I served our country as a Rifleman in the United States Marine Corps.
13 In May 1996, I joined Chrysler Corporation and held various positions with progressing
14 levels of responsibility at the Trenton Engine Plant, progressing from a Technical Advisor
15 to Area Manager. In September 2002, I joined Delphi Corporation as a Production
16 Supervisor and, in September 2004, progressed to a Senior Manufacturing Engineer. In
17 July 2008, I joined Consumers Energy at the D.E. Karn (“Karn”)/ J.C. Weadock
18 (“Weadock”) Generating Complex and progressed through positions from Senior Engineer
19 to the Site Business Manager. In June 2015, I transferred to the B.C. Cobb (“Cobb”)
20 Generating Complex and J.H. Campbell (“Campbell”) Generating Complex as the Site
21 Business Manager for both facilities. Following the closure of seven of the Company’s
22 coal-fired units at its Cobb, Weadock, and J.R. Whiting (“Whiting”) sites (collectively, the
23 “Classic 7”) in 2016, I was promoted to Executive Director of Coal Generation. In April

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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

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activity costs related to the early retirement of its existing generating units at the Campbell and Karn generating sites; (v) Consumers Energy's avoidable and incremental capital expenditures and expenses in different cases involving the early retirement of Campbell Units 1 and 2, Campbell Unit 3, and Karn Units 3 and 4; (vi) the performance of the Company's existing generation fleet; (vii) execution risks faced by Consumers Energy if Campbell Units 1, 2, or 1 and 2, Campbell Unit 3, or Karn Units 3 and 4 are selected for early retirement; and (viii) the tax, community, and employee impacts of an early retirement case.

Q. What is the Company's retirement recommendation with respect to Campbell Units 1 and 2, Campbell Unit 3, and Karn Units 3 and 4?

A. As discussed by several Company witnesses, and as also further explained in my direct testimony, Consumers Energy's PCA proposes to retire Karn Units 3 and 4 in 2023, and retire Campbell Units 1, 2, and 3 in 2025. As discussed in Section II of my testimony, this PCA will result in \$75,648,000 in avoided capital expenditures, \$15,645,00 in avoided unit separation capital expenditures, and \$10,050,000 in avoided major maintenance expenses at Karn Units 3 and 4 compared to the Company's base case outlook ("base case"). In addition, this PCA will result in ~~\$190,613,000~~\$136,244,000 in avoided capital expenditures, \$64,146,000 in avoided unit separation capital expenditures, and \$57,555,000 in avoided major maintenance expenses at Campbell Unit 3; \$12,114,000 in avoided capital expenditures and \$61,524,000 in avoided major maintenance expenses at Campbell Unit 1; and \$13,385,000 in avoided capital expenditures and \$84,186,000 in avoided major maintenance expenses at Campbell Unit 2, compared to the Company's base case

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assumptions of continued operations to the units current design lives in each of the scenarios described by Company witness Sara T. Walz.

Q. Are there any offsets to the avoided cost numbers?

A. Yes. The avoided capital expenditures, avoided unit separation capital expenditures, and avoided major maintenance expenses would be partially offset by the capital expenditures and O&M expenses for the Covert, DIG, Kalamazoo, and Livingston gas generating plants (collectively “new gas plants”) which are discussed in Section III of my direct testimony. The Company is also projecting that it will incur approximately \$60,000,000 in employee retention and separation activity expenses, as discussed in Section VIII of my direct testimony; however, the Company does not consider these costs incremental in nature as the Company would have incurred these costs at a later date had an early retirement not occurred.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-50 (NJK-1) <u>Revised</u>	Summary of Capital Expenditures and Operations and Maintenance Expenses;
Exhibit A-51 (NJK-2) <u>Revised</u>	Summary of Projected Generation Operations Capital Expenditures;
Exhibit A-52 (NJK-3)	Summary of Projected Generation Operations Major Maintenance Expenses;
Exhibit A-53 (NJK-4)	Summary of Projected Generation Operations Base O&M Expenses;
Exhibit A-54 (NJK-5)	Generation Operations – Summary of Capital Expenditures and Costs of Removal;

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1	Exhibit A-55 (NJK-6) <u>Revised</u>	Summary of Projected Generation
2		Operations Capital Expenditures and
3		Operations and Maintenance
4		Expenses – new gas plants;
5	Exhibit A-56 (NJK-7)	Summary of Projected Generation
6		Operations Separation Activity
7		Capital Expenditures;
8	Exhibit A-57 (NJK-8) <u>Revised</u>	Generation Capital Expenses –
9		Avoidable And Incremental Under
10		an Early Retirement Case 2024 -
11		2032;
12	Exhibit A-58 (NJK-9)	Generation Major Maintenance
13		Expenses – Avoidable Under An
14		Early Retirement Case 2024-2032;
15	Exhibit A-59 (NJK-10)	Generating Unit Random Outage
16		Rates; and
17	Confidential Exhibit A-60 (NJK-11)	Generating Unit Heat Rates.

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

A. Yes.

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SECTION I: EXISTING GENERATION RESOURCES

Q. Please provide an overview of the Company's non-renewable energy generation assets.

A. As of 2020, the Company's total non-renewable owned generation assets had a net demonstrated summer operating capability of 5,292 MW, comprised of the following coal-, oil-, or gas-fired; hydroelectric; and pumped storage facility units:

TABLE 1

RESOURCE	MICHIGAN LOCATION	IN-SERVICE DATE	AGE (years)	RETIREMENT DATE	REMAINING EST. TIME OF OPERATION (years)	LICENSING STATUS	NET GENERATING CAPABILITY (MW)
COAL FIRED							
JH Campbell 1	West Olive, MI	1962	59	2031	10	Active	260
JH Campbell 2	West Olive, MI	1967	54	2031	10	Active	260
JH Campbell 3	West Olive, MI	1980	41	2039	18	Active	785 (owned share)
DE Karn 1	Essexville, MI	1959	62	2023	2	Active	255
DE Karn 2	Essexville, MI	1961	60	2023	2	Active	258
OIL OR GAS FIRED							
DE Karn 3	Essexville, MI	1975	46	2031	10	Active	362
DE Karn 4	Essexville, MI	1977	44	2031	10	Active	362
Zeeland CC	Zeeland, MI	2002	19	2041	20	Active	575
Zeeland 1A	Zeeland, MI	2002	19	2041	20	Active	180
Zeeland 1B	Zeeland, MI	2002	19	2041	20	Active	180
Jackson	Jackson, MI	2002	19	2041	20	Active	547
HYDROELECTRIC							
Alcona	Alcona County, MI	1924	97	n/a	n/a	Active	8
Allegan	Allegan County, MI	1936	85	n/a	n/a	Active	3
Cooke	Iosco County, MI	1911	110	n/a	n/a	Active	9
Croton	Newaygo County, MI	1907	114	n/a	n/a	Active	9
Five Channels	Iosco County, MI	1912	109	n/a	n/a	Active	6
Footte	Iosco County, MI	1918	103	n/a	n/a	Active	9
Hardy	Newaygo County, MI	1931	90	n/a	n/a	Active	30
Hodenpyl	Wexford County, MI	1925	96	n/a	n/a	Active	17
Loud	Iosco County, MI	1913	108	n/a	n/a	Active	4
Mio	Oscoda County, MI	1916	105	n/a	n/a	Active	5
Rogers	Mecosta County, MI	1906	115	n/a	n/a	Active	7
Tippy	Manistee County, MI	1918	103	n/a	n/a	Active	21
Webber	Ionia County, MI	1907	114	n/a	n/a	Active	3
ENERGY STORAGE							
Ludington Units 1-6	Ludington, MI	1973	48	2069	48	Active	1138 (owned share)

Q. What does "owned share" mean when used with respect to Campbell Unit 3?

A. The Company owns approximately 93% of Campbell Unit 3. Michigan Public Power Agency and Wolverine Power Supply Cooperative, Inc. own the remaining 7%. Thus, the 785 MW capacity reported is 93% of the Campbell Unit 3 net demonstrated summer operating capability, reflecting the Company's share of ownership.

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1 **Q. What does “owned share” mean when used with respect to Ludington Pumped**
 2 **Storage Plant (“Ludington” or the “Ludington Plant”) Units 1-6?**

3 A. The Company owns 51% of the Ludington Plant and DTE Electric Company owns the
 4 remaining 49%. Thus, the 1,138 MW capacity reported is 51% of the total Ludington Plant
 5 net demonstrated summer operating capability, reflecting the Company’s share of
 6 ownership.

7 **SECTION II: PROJECTED CAPITAL EXPENDITURES AND O&M EXPENSES**
 8 **OF EXISTING GENERATION FLEET**

9 **Q. Please explain Exhibit A-50 (NJK-1) Revised.**

10 A. Exhibit A-50 (NJK-1) Revised shows the projected capital expenditures and major
 11 maintenance expenses for the Campbell Units 1, 2, and 3; Karn Units 1 and 2; and Karn
 12 Units 3 and 4 for the period of January 1, 2020 through May 31, 2031, and the base O&M
 13 expenses for the Campbell Units 1, 2, and 3; Karn Units 1 and 2; and Karn Units 3 and 4
 14 for the same period, under a variety of cases. These are the costs and the date range that
 15 the Company used for modeling purposes in this IRP. The Company evaluated a base case,
 16 in which all four units (Karn Units 3 and 4 and Campbell Units 1 and 2) retire on May 31,
 17 2031, and then evaluated sixteen early retirement cases related to the Karn and Campbell
 18 sites:

- 19 • Retirement of Karn Units 3 and 4 on May 31, 2023;
- 20 • Retirement of Karn Units 3 and 4 on May 31, 2025;
- 21 • Retirement of Campbell Unit 3 on May 31, 2025;
- 22 • Retirement of Campbell Unit 3 on May 31, 2032;
- 23 • Retirement of Campbell Unit 1 on May 31, 2024;
- 24 • Retirement of Campbell Unit 1 on May 31, 2025;

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- Retirement of Campbell Unit 1 on May 31, 2026;
- Retirement of Campbell Unit 1 on May 31, 2028;
- Retirement of Campbell Unit 2 on May 31, 2024;
- Retirement of Campbell Unit 2 on May 31, 2025;
- Retirement of Campbell Unit 2 on May 31, 2026;
- Retirement of Campbell Unit 2 on May 31, 2028;
- Retirement of Campbell Units 1 and 2 on May 31, 2024;
- Retirement of Campbell Units 1 and 2 on May 31, 2025;
- Retirement of Campbell Units 1 and 2 on May 31, 2026; and
- Retirement of Campbell Units 1 and 2 on May 31, 2028.

Q. Please explain Exhibit A-50 (NJK-1) Revised, pages 1 and 2.

A. Exhibit A-50 (NJK-1) Revised, pages 1 and 2, presents the total capital expenditures projected to be made at the Karn and Campbell sites by the Company in each of the sixteen cases listed above. With the exception of Campbell Unit 3, the capital expenditure amounts presented for each unit in each case is a total of all capital expenditures for the period of January 1, 2020 through May 31, 2031. The capital expenditure amounts for Campbell Unit 3 reflect projected amounts through May 31, 2039. For each of the sixteen early retirement cases, the exhibit presents both the total capital expenditures (including unit separation) over that period that would be made in each respective case and the difference in capital expenditures over that period relative to the base case. Exhibit A-50 (NJK-1) Revised, page 1, lines 2 and 3 reflects the early retirement cases for Karn Units 3 and 4; for these cases, the capital expenditures for Karn Units 3 and 4 are reduced versus those shown in the base case. As shown in Exhibit A-50 (NJK-1) Revised, page 1, lines 2 and

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3, columns (b) and (c), the 2023 retirement case results in both reduced capital expenditures and also reduced separation costs at Karn Units 3 and 4, and the 2025 retirement case results in reduced capital expenditures at Karn Units 3 and 4, which will be discussed later in my direct testimony. Likewise, Exhibit A-50 (NJK-1) Revised, page 1, lines 4 and 5, reflects the early retirement cases for Campbell Unit 3; for each of these cases, both the capital expenditures and separation costs for Campbell Unit 3 are also reduced from those shown in the base case. Exhibit A-50 (NJK-1) Revised, pages 1-2, lines 6 through 17, reflects the retirement cases for which Campbell Unit 1 retires, Campbell Unit 2 retires, or both Campbell Units 1 and 2 retire. Exhibit A-50 (NJK-1) Revised, pages 1 and 2, lines 6 through 13, columns (c) and (d), shows the reduced or incremental costs for Campbell Units 1 and 2 versus the base case for the individual unit retirements. Exhibit A-50 (NJK-1) Revised, page 2, lines 14 through 17, columns (c) and (d), show reduced costs at Campbell Units 1 and 2 when both units retire. No incremental costs are projected at Campbell Unit 3 versus the base case for the cases in which Campbell Units 1 and 2 both retire. Costs of removal are not included in any of the cases in Exhibit A-50 (NJK-1) Revised, page 1, nor are environmental costs related to Steam Electric Effluent Guidelines (“SEEG”) and Clean Water Act Section 316(b) (“316(b)”). Those environmental costs are discussed by Company witness Heather A. Breining.

Q. Please explain Exhibit A-50 (NJK-1) Revised, pages 3 and 4.

A. Exhibit A-50 (NJK-1) Revised, pages 3 and 4, presents the total major maintenance expenses projected to be made at the Karn and Campbell sites by the Company in each of the sixteen cases listed above. With the exception of Campbell Unit 3, the major maintenance expenses presented for each unit in each case is a total of all major

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1 maintenance expenses for the period of January 1, 2020 through May 31, 2031. The major
2 maintenance expenses for Campbell Unit 3 reflect projected amounts through May 31,
3 2039. For each of the 16 early retirement cases, the exhibit presents both the total major
4 maintenance expenses over that period that would be made in each respective case, and the
5 difference in major maintenance expenses over that period relative to the base case. Exhibit
6 A-50 (NJK-1) **Revised**, page 3, lines 2 and 3, reflects the early retirement cases for Karn
7 Units 3 and 4; for these cases, the major maintenance expenses for Karn Units 3 and 4 are
8 reduced from those shown in the base case. Likewise, Exhibit A-50 (NJK-1) **Revised**, page
9 3, lines 4 and 5, reflects the early retirement cases for Campbell Unit 3; for each of these
10 cases, the major maintenance expenses for Campbell Unit 3 are also reduced from those
11 shown in the base case. Exhibit A-50 (NJK-1) **Revised**, pages 3 and 4, lines 6 through 17,
12 reflects the retirement cases for which Campbell Unit 1 retires, Campbell Unit 2 retires, or
13 both Campbell Units 1 and 2 retire. Exhibit A-50 (NJK-1) **Revised**, pages 3 and 4, lines 6
14 through 13, columns (c) and (d), shows the reduced major maintenance expenses for
15 Campbell Units 1 and 2 versus the base case for the individual unit retirements. Exhibit
16 A-50 (NJK-1) **Revised**, page 2, lines 14 through 17 columns (c) and (d), shows reduced
17 costs at Campbell Units 1 and 2 when both units retire. No incremental major maintenance
18 expenses are projected at Campbell Unit 3 versus the base case for the cases in which
19 Campbell Units 1 and 2 both retire. Exhibit A-50 (NJK-1) **Revised**, pages 3 and 4, does
20 not include environmental costs related to SEEG and Clean Water Act Section 316(b)
21 (“316(b)”). Those environmental costs are discussed by Company witness Breining.

22 **Q. Please explain Exhibit A-50 (NJK-1) **Revised**, pages 5 and 6.**

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1 A. Exhibit A-50 (NJK-1) Revised, pages 5 and 6, presents the total O&M expenses projected
2 to be made at the Karn and Campbell sites by the Company in each of the sixteen cases
3 listed above. With the exception of Campbell Unit 3, the O&M expenses presented for
4 each unit in each case is a total of all O&M expenses for the period of January 1, 2020
5 through May 31, 2031. The O&M expenses for Campbell Unit 3 reflect projected amounts
6 through May 31, 2039. For each of the 16 early retirement cases, the exhibit presents both
7 the total O&M expenses over that period that would be made in each respective case and
8 the difference in O&M expenses over that period relative to the base case. Exhibit A-50
9 (NJK-1) Revised, page 5, lines 2 and 3, reflects the early retirement cases for Karn Units 3
10 and 4; for these cases, the O&M expenses for Karn Units 3 and 4 are reduced from those
11 shown in the base case. Likewise, Exhibit A-50 (NJK-1) Revised, page 5, lines 4 and 5,
12 reflects the early retirement cases for Campbell Unit 3; for each of these cases, the O&M
13 expenses for Campbell Unit 3 are also reduced from those shown in the base case. Exhibit
14 A-50 (NJK-1) Revised, pages 5 and 6, lines 6 through 17, reflects the retirement cases for
15 which Campbell Unit 1 retires, Campbell Unit 2 retires, or both Campbell Units 1 and 2
16 retire. Exhibit A-50 (NJK-1) Revised, pages 5 and 6, lines 6 through 9, columns (c), (d),
17 and (e), shows the reduced O&M expenses for Campbell Unit 1 retirement and increased
18 O&M expenses for Campbell Units 2 and 3 versus the base case for the individual unit
19 retirements. Exhibit A-50 (NJK-1) Revised, pages 5 and 6, lines 10 through 13, columns
20 (c), (d), and (e), shows the reduced O&M expenses for Campbell Unit 2 retirement and
21 increased O&M expenses for Campbell Units 1 and 3 versus the base case for the individual
22 unit retirements. Exhibit A-50 (NJK-1) Revised, page 2, lines 14 through 17, columns (c),
23 (d), and (e), shows the reduced O&M expenses for Campbell Units 1 and 2 when both units

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1 retire and increased O&M expenses for Campbell Unit 3. Exhibit A-50 (NJK-1) Revised,
 2 pages 5 and 6 do not include environmental costs related to SEEGand Clean Water Act
 3 Section 316(b) (“316(b)”). Those environmental costs are discussed by Company witness
 4 Breining.

5 **Q. Please explain Exhibit A-51 (NJK-2) Revised, page 1.**

6 A. Exhibit A-51 (NJK-2) Revised, page 1, shows the Company’s projected capital
 7 expenditures for the Company’s generating units at the Campbell and Karn sites for each
 8 calendar year over the period from January 1, 2020 through May 31, 2039 in the base case
 9 retirement case. In this case, Karn Units 1 and 2 retire on May 31, 2023, Karn Units 3 and
 10 4 and Campbell Units 1 and 2 retire on May 31, 2031, and Campbell Unit 3 retires on May
 11 31, 2039.

12 **Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2)**
 13 **Revised, page 1, line 1?**

14 A. The capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 1, are those that
 15 were used for 2020 in the Company’s IRP modeling.

16 **Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2)**
 17 **Revised, page 1, line 2?**

18 A. In 2021, the Company projects to spend:

- 19 • \$2,859,236 at Karn Units 1 and 2, covering seventeen projects, none of which
 20 exceed \$500,000;
- 21 • \$4,172,000 at Karn Units 3 and 4, including:
 - 22 o Auxiliary Boiler System Optimization (\$2,000,000);
 - 23 o Replace House Service Water Screen Drives (\$950,000); and
 - 24 o Twenty-seven additional projects totaling \$1,222,000, with no individual
 25 project exceeding \$300,000;

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- \$3,493,440 at Campbell Unit 1, including:
 - o Re-align 4160V switchgear with Air Quality Control System (“AQCS”) implementation (\$1,000,000); and
 - o Eleven additional projects totaling \$2,493,440, with no individual project exceeding \$696,000;
- \$13,512,160 at Campbell Unit 2, including:
 - o Low Pressure Turbine Overhaul (\$3,500,000);
 - o Secondary Air Heater Basket and Seal Replacement (\$1,750,000);
 - o Pulse Jet Fabric Filter (“PJFF”) Bag Replacement (\$2,394,000); and
 - o Seventeen additional projects totaling \$5,868,160, with no individual project exceeding \$858,100; and
- \$19,576,382 at Campbell Unit 3, including:
 - o Selective Catalytic Reduction (“SCR”) Reactor Catalyst Management (\$1,959,510);
 - o Replace CO-O2 Monitors (\$1,044,600);
 - o Mill Complete Overhauls (\$1,235,000);
 - o Reheater Sootblower (\$1,250,000);
 - o Sootblowing Air Upgrade (\$1,200,000);
 - o Replace Lake Michigan Intake Screens (\$1,339,000);
 - o Cell Construction and Permitting (\$5,482,830); and
 - o Twenty-two additional projects totaling \$6,06,442, with no individual project exceeding \$750,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2)

Revised, page 1, line 3?

A. In 2022, the Company projects to spend

- \$2,135,136 at Karn Units 1 and 2, covering 12 projects, none of which exceeds \$350,000;

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- \$15,416,000 at Karn Units 3 and 4, including:
 - o Tank Farm Storage Tank Heating Lines (\$1,400,000);
 - o Karn Sync Wire Replacement (\$1,320,000);
 - o Auxiliary Boiler System Optimization (\$1,160,000);
 - o Parking Lot Replacement (\$1,000,000);
 - o Karn 3 Ductwork Expansion Joint Replacement (\$3,000,000);
 - o Karn 3 Cooling Tower Rebuild (\$2,500,000); and
 - o Twenty-two additional projects totaling \$5,036,000, with no individual project exceeding \$450,000;
- \$7,300,000 at Campbell Unit 1, including:
 - o PJFF Bag Replacement (\$1,578,000);
 - o Superheat Outlet Pendant – partial replacement (\$3,490,000); and
 - o Five additional projects totaling \$2,232,000, with no individual project exceeding \$750,000;
- \$5,256,500 at Campbell Unit 2, including:
 - o Catalyst Management (\$1,120,000);
 - o Replace Burner Assemblies (\$1,350,000); and
 - o Six additional projects totaling \$2,786,500, with no individual project exceeding \$836,500; and
- \$17,125,333 at Campbell Unit 3, including:
 - o PJFF Bag & Cleaning Air Manifold Replacement (\$3,994,601);
 - o SCR Reactor Catalyst Management (\$1,866,200);
 - o Complete Mill Overhauls (\$1,264,800);
 - o Replace CO-O2 Monitors (\$967,400);
 - o Design and Install New Large Particle Ash Screen (\$1,485,100);
 - o Fuel Handling & Infrastructure Repairs (\$1,500,000); and

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- o Sixteen additional projects totaling \$6,047,032, with no individual project exceeding \$889,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2)

Revised, page 1, line 4?

A. In 2023, the Company projects to spend:

- \$1,123,678 at Karn Units 1 and 2, covering 12 projects, none of which exceeds \$235,136;
- \$10,072,000 at Karn Units 3 and 4, including:
 - o Distributed Control System Evergreen Project (\$1,000,000);
 - o Karn 3 Ductwork Expansion Joint Replacement (\$1,000,000);
 - o Karn 3 Cooling Tower Rebuild (\$4,800,000);
 - o Capital Equipment Repairs (\$1,000,000); and
 - o Twelve additional projects totaling \$2,272,000, with no individual project exceeding \$758,000;
- \$7,214,680 at Campbell Unit 1, including:
 - o PJFF Filter Bag Replacement (\$1,514,100);
 - o Replace Air Preheater Baskets and Seals (\$1,113,400);
 - o Distributed Control System and Simulator Upgrade (\$1,500,000);
 - o Ashpit Rebuild (\$1,000,000); and
 - o Twelve additional projects totaling \$2,087,180, with no individual project exceeding \$750,000;
- \$9,472,020 at Campbell Unit 2, including:
 - o Horizontal Reheat Replacement (\$5,053,000);
 - o SCR Reactor Catalyst Replacement (\$2,000,000); and
 - o Nine additional projects totaling \$2,419,020, with no individual project exceeding \$750,000; and
- ~~\$20,766,757~~\$20,478,187 at Campbell Unit 3, including:

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- o PJFF Bag & Cleaning Air Manifold Replacement (\$3,263,331);
- o Complete Mill Overhauls (\$1,295,300);
- o Design and Install New Large Particle Ash Screen (\$1,008,700);
- o Secondary Air Heater basket & seal replacement (\$2,425,000)
- o High Pressure Feedwater Heater 8A replacement (\$5,039,800);
- o Fuel Handling & Infrastructure Repairs (\$1,500,000); and
- o ~~Eighteen-Seventeen~~ additional projects totaling ~~\$7,242,827~~\$6,954,257, with no individual project exceeding \$750,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2)

Revised, page 1, line 5?

A. In 2024, the Company projects to spend:

- \$9,775,000 at Karn Units 3 and 4, including:
 - o Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack (\$800,000);
 - o Karn 3 Cooling Tower Rebuild (\$4,950,000);
 - o Capital Equipment Repairs (\$3,000,000); and
 - o Twelve additional projects totaling \$2,272,000, with no individual project exceeding \$758,000;
- \$9,753,000 at Campbell Unit 1 including:
 - o Replace Burners Corner 1-8 (\$2,700,000);
 - o Replace Air Preheater Baskets and Seals (\$1,137,100);
 - o Boiler Component Replacement (\$3,000,000);
 - o Balance of Plant Equipment Replacement (\$1,500,000) and
 - o Six additional projects totaling \$1,415,900, with no individual project exceeding \$815,900;
- \$11,252,000 at Campbell Unit 2, including:
 - o Horizontal Reheat Replacement (\$7,952,000);

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- o Distributed Control System and Simulator Upgrade (\$1,500,000); and
- o Four additional projects totaling \$1,800,000, with no individual project exceeding \$750,000; and
- ~~\$35,780,799~~\$33,395,569 at Campbell Unit 3, including:
 - o SCR Reactor Catalyst Management (\$1,959,510);
 - o Turbine Drain Modifications (\$2,535,000);
 - o Superheat Terminal Drain Replacement (\$3,023,100);
 - o Replace Boiler Sidewall Panels (\$2,425,000);
 - o Replace Boiler Front And Rear Wall Panels (\$2,482,900);
 - o Secondary Air Heater basket & seal replacement (\$1,562,000);
 - o Fuel Handling & Infrastructure Repairs (\$1,500,000);
 - ~~o Dry Ash Landfill Closure (\$1,635,230);~~
 - o Cell Construction and Permitting (\$5,482,830); and
 - o ~~Twenty-two~~Twenty-one additional projects totaling ~~\$10,600,029~~\$12,425,229, with no individual project exceeding \$933,100.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2)

Revised, page 1, line 6?

A. In 2025, the Company projects to spend:

- \$10,134,000 at Karn Units 3 and 4, including:
 - o Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack (\$2,500,000);
 - o Karn 3 Cooling Tower Rebuild (\$2,565,000);
 - o Capital Replacements (\$4,000,000); and
 - o Three additional projects totaling \$1,069,000, with no individual project exceeding \$750,000;
- \$2,550,000 at Campbell Unit 1, including four projects that do not exceed \$669,000 individually; and

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- \$7,800,000 at Campbell Unit 2, including:
 - Replace turbine right side Reheat Stop Valve body (\$1,850,000); and
 - Boiler Component Replacement (\$3,000,000);
- Five additional projects totaling \$2,950,000, with no individual project exceeding \$750,000; and
- ~~\$30,179,045~~ \$14,512,045 at Campbell Unit 3, including:
 - GSU Replacement (\$6,485,045);
 - SCR Reactor Catalyst Management (\$3,000,000);
 - AQCS Equipment repair/replacement (\$1,000,000);
 - ~~Part 115 JH Campbell B-K landfill cap (\$15,667,000)~~
 - Cell Construction and Permitting (\$2,000,000); and
 - Four additional projects totaling \$2,027,000, with no individual project exceeding \$750,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2)

Revised, page 1, line 7?

A. In 2026, the Company projects to spend:

- \$9,900,000 at Karn Units 3 and 4, including:
 - Karn 3 Ductwork Replace Insulation & Lagging - ID Fan to Stack (\$4,000,000);
 - Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack (\$3,000,000);
 - Capital Replacements (\$2,000,000); and
 - Three additional projects totaling \$6,050,000, with no individual project exceeding \$250,000;
- \$3,300,000 at Campbell Unit 1, including five projects that do not exceed \$750,000 individually;
- \$4,420,000 at Campbell Unit 2, including:

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- o Catalyst Management (\$1,120,000); and
- o Five additional projects totaling \$3,300,000, with no individual project exceeding \$750,000; and
- ~~\$29,053,000~~ \$4,400,000 at Campbell Unit 3, including:
 - o ~~Replace Air and Flue Gas Expansion Joints (\$2,000,000);~~
 - o ~~Part 115 JH Campbell B-K landfill cap (\$24,653,000);~~ and
 - o Four additional projects totaling \$2,400,000, with no individual project exceeding \$750,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, lines 8 through 20?

A. In each year from 2027 through 2039 in the base case, the Company projects to incur capital expenditures at Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3, as shown in Exhibit A-51 (NJK-2) Revised, page 1. The capital projects for Karn Units 3 and 4 are as follows:

- 2027: Four projects totaling \$8,950,000, which includes:
 - o K3 Ductwork Replace Insulation & Lagging - ID Fan to Stack (\$2,600,000);
 - o Karn 3 Distributed Control System (“DCS”) & Simulator Evergreen (\$1,000,000);
 - o Karn 4 DCS & Simulator Evergreen (\$1,350,000); and
 - o Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack (\$4,000,000);
- 2028-2029: One project each year totaling \$2,000,000, for capital replacements;
- 2030: One project totaling \$1,000,000, for capital replacements; and
- 2031: One project totaling \$500,000, for capital replacements.

The capital projects for Campbell Unit 1 are as follows:

- 2027: Five projects totaling \$4,050,000, which include:

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- o DCS and Simulator Upgrade (\$1,500,000); and
- o Four additional projects totaling \$2,550,000, with no individual project exceeding \$750,000;
- 2028: Four projects totaling \$3,500,000, which include:
 - o Fuel Handling and Infrastructure Replacements (\$1,000,000);
 - o AQCS Equipment Repair/Replacement (\$1,000,000); and
 - o Two additional projects totaling \$1,500,000, with no individual project exceeding \$750,000;
- 2029: Five projects totaling \$3,878,000, which includes:
 - o PJFF Filter Bag Replacement (\$1,578,000);
 - o AQCS Equipment repair/replacement (\$1,000,000); and
 - o Three additional projects totaling \$1,300,000, with no individual project exceeding \$500,000;
- 2030: Five projects totaling \$2,563,000, which include:
 - o PJFF Filter Bag Replacement (\$1,513,600); and
 - o Four additional projects totaling \$1,050,000, with no individual project exceeding \$300,000; and
- 2031: One Project totaling \$250,000.

The capital projects for Campbell Unit 2 are as follows:

- 2027: Eight projects totaling \$6,845,000, which include:
 - o Catalyst Management (\$2,806,000);
 - o PJFF bag replacement (\$1,389,000); and
 - o Six projects totaling \$2,650,000 with no individual project which exceeds \$750,000;
- 2028: Six projects totaling \$7,394,000, which include:
 - o DCS and Simulator Upgrade (\$1,500,000);
 - o PJFF bag replacement (\$1,389,000);

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- o Fuel Handling and Infrastructure Replacements (\$1,000,000);
- o AQCS Equipment repair/replacement (\$1,000,000); and
- o Two projects totaling \$1,500,000 with no individual project which exceeds \$500,000;
- 2029: Five projects totaling \$2,500,000, which include;
 - o AQCS Equipment repair/replacement (\$1,000,000); and
 - o Four projects totaling \$1,894,333 with no individual project which exceeds \$500,000;
- 2030: Four projects totaling \$1,050,000, with no individual project which exceeds \$300,000; and
- 2031: One project totaling \$250,000.

The capital projects for Campbell Unit 3 are as follows:

- 2027: ~~Six~~ Five projects totaling ~~\$30,563,600~~ \$5,900,000, including:
 - o ~~Cell Construction and Permitting (\$3,500,000);~~
 - o ~~Part 115 JH Campbell B-K landfill cap (\$24,663,000);~~ and
 - o Four additional projects totaling \$2,400,000, with no individual project exceeding \$750,000;
- 2028: Five projects totaling \$4,400,000, including:
 - o SCR Reactor Catalyst Management (\$2,000,000); and
 - o Four additional projects totaling \$2,400,000, with no individual project exceeding \$750,000;
- 2029: Six projects totaling \$11,750,000, which include:
 - o SCR Reactor Catalyst Management (\$3,000,000);
 - o Boiler Component Replacement (\$5,000,000);
 - o AQCS Equipment repair/replacement (\$2,000,000); and
 - o Three additional projects totaling \$1,750,000, with no individual project exceeding \$750,000;

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- 1 • 2030: ~~Four~~ Five projects totaling ~~\$4,650,000~~ \$11,150,000, which include:
 - 2 o SCR Reactor Catalyst Management (\$3,000,000);
 - 3 o Cell Construction and Permitting (\$6,500,000);
 - 4 o AQCS Equipment repair/replacement (\$3,000,000); and
 - 5 o Three additional projects totaling \$1,650,000, with no individual project
 - 6 exceeding \$750,000;
- 7 • 2031: Four projects totaling \$2,400,000, with no individual project which
- 8 exceeds \$750,000;
- 9 • 2032: Four projects totaling \$2,750,000, which include:
 - 10 o AQCS Equipment repair/replacement (\$1,000,000); and
 - 11 o Three additional projects totaling \$1,750,000, with no individual project
 - 12 exceeding \$750,000;
- 13 • 2033: Seven projects totaling \$11,750,000, which include:
 - 14 o SCR Reactor Catalyst Management (\$2,000,000);
 - 15 o Replace Air and Flue Gas Expansion Joints (\$2,000,000);
 - 16 o Boiler Component Replacement (\$5,000,000);
 - 17 o AQCS Equipment Repair/Replacement (\$1,000,000); and
 - 18 o Three additional projects totaling \$1,750,000, with no individual project
 - 19 exceeding \$750,000;
- 20 • 2034: Five projects totaling \$5,400,000, which include:
 - 21 o SCR Reactor Catalyst Management (\$3,000,000); and
 - 22 o Four additional projects totaling \$2,400,000, with no individual project
 - 23 exceeding \$750,000;
- 24 • 2035: ~~Five~~ Four projects totaling ~~\$3,650,000~~ \$10,150,000, which include:
 - 25 o AQCS Equipment repair/replacement (\$2,000,000);
 - 26 o Cell Construction and Permitting (\$6,500,000); and
 - 27 o Three additional projects totaling \$1,650,000, with no individual project
 - 28 exceeding \$750,000;

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- 2036: Four projects totaling \$4,650,000, which include:
 - o AQCS Equipment repair/replacement (\$3,000,000); and
 - o Three additional projects totaling \$1,650,000, with no individual project exceeding \$750,000;
- 2037: Four projects totaling \$2,400,000, with no individual project which exceeds \$750,000; and
- 2038: Two projects totaling \$550,600, with no individual project which exceeds \$300,000.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 2.

A. Exhibit A-51 (NJK-2) Revised, page 2, shows the Company's projected capital expenditures for Karn Units 3 and 4 for the cases in which Karn Units 3 and 4 retire on May 31, 2023 or May 31, 2025. As shown in Exhibit A-51 (NJK-2) Revised, page 2, column (c), there are no projected incremental capital expenditures for Karn Units 1 and 2 in these cases, which are discussed later in my direct testimony. The projected capital expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2) Revised, page 2, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 2, line 13, column (d), shows that the Company would avoid \$75,648,000 in capital expenditures if Karn Units 3 and 4 are retired on May 31, 2023. Exhibit A-51 (NJK-2) Revised, page 2, line 13, column (i), shows that the Company would avoid \$62,987,000 in capital expenditures if Karn Units 3 and 4 are retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 2, line 13, columns (e) and (j), shows that the Company would avoid \$15,465,000 in unit separation capital expenditures and \$9,161,000 in unit separation

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capital expenditures if Karn Units 3 and 4 are retired on May 31, 2023 and May 31, 2025 respectively.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 3.

A. Exhibit A-51 (NJK-2) Revised, page 3, shows the Company's projected capital expenditures for Campbell Unit 3 for the cases in which Campbell Unit 3 retires on May 31, 2025 or on May 31, 2032. The projected capital expenditures are shown for each calendar year from January 1, 2020 through May 31, 2039. Exhibit A-51 (NJK-2) Revised, page 3, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 3, line 21, columns (c) and (d), show that the Company would avoid \$190,613,000 in capital expenditures and \$64,146,000 in unit separation capital expenditures if Campbell Unit 3 is retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 3, line 21, columns (g) and (h), shows that the Company would avoid \$31,400,000 in capital expenditures and \$64,146,000 in unit separation capital expenditures if Campbell Unit 3 is retired on May 31, 2032. Campbell Units 1 and 2 are not reflected in Exhibit A-51 (NJK-2) Revised, page 3, because the Campbell Unit 3 early retirement case assumes that Campbell Units 1 and 2 retire in a similar timeframe and, therefore, have identical costs to those in the base case through 2026 and 2032.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 4.

A. Exhibit A-51 (NJK-2) Revised, page 4, shows the Company's projected capital expenditures for Campbell Units 1 and 2 for the cases in which Campbell Unit 1 retires on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2) Revised, page 4, also shows the difference in capital expenditures

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1 for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 4,
2 line 13, columns (d) and (e), shows that the Company would avoid \$42,840,000 in capital
3 expenditures if Campbell Unit 1 is retired on May 31, 2024 and Campbell Unit 2 would
4 incur incremental capital expenditures of \$253,000. Exhibit A-51 (NJK-2) Revised, page
5 4, line 13, columns (i) and (j), show that the Company would avoid \$35,951,000 in capital
6 expenditures at Campbell Unit 1 and incur no incremental capital expenditures at Campbell
7 Unit 2 if Campbell Unit 1 is retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page
8 4, line 26, columns (d) and (e), shows that the Company would avoid \$34,046,000 in capital
9 expenditures at Campbell Unit 1 and incur no incremental capital expenditures at Campbell
10 Unit 2 if Campbell Unit 1 is retired on May 31, 2026. Exhibit A-51 (NJK-2) Revised, page
11 4, line 26, columns (i) and (j), shows that the Company would avoid \$14,442,000 in capital
12 expenditures at Campbell Unit 1 and incur no incremental capital expenditures at Campbell
13 Unit 2 if Campbell Unit 1 is retired on May 31, 2028. Campbell Unit 3 is not reflected in
14 Exhibit A-51 (NJK-2) Revised, page 4, because the Campbell early retirement cases do not
15 have an impact on the Campbell Unit 3 capital expenditures as it is assumed that unit
16 separation capital expenditures reflected in the base case are not avoided.

17 **Q. Please explain Exhibit A-51 (NJK-2) Revised, page 5.**

18 A. Exhibit A-51 (NJK-2) Revised, page 5, shows the Company's projected capital
19 expenditures for Campbell Units 1 and 2 for the cases in which Campbell Unit 2 retires on
20 May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected
21 expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031.
22 Exhibit A-51 (NJK-2) Revised, page 5, also shows the difference in capital expenditures
23 for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 5,

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line 13, columns (d) and (e), shows that the Company would avoid \$56,070,000 in capital expenditures if Campbell Unit 2 is retired on May 31, 2024, and Campbell Unit 1 would incur incremental capital expenditures of \$322,000. Exhibit A-51 (NJK-2) Revised, page 5, line 13, columns (i) and (j), shows that the Company would avoid \$46,573,000 in capital expenditures at Campbell Unit 2 and incur no incremental capital expenditures at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 4, line 26, columns (d) and (e), shows that the Company would avoid \$45,273,000 in capital expenditures at Campbell Unit 2 and incur no incremental capital expenditures at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2026. Exhibit A-51 (NJK-2) Revised, page 4, line 26, columns (i) and (j), shows that the Company would avoid \$18,333,000 in capital expenditures at Campbell Unit 2 and incur no incremental capital expenditures at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-51 (NJK-2) Revised, page 5, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 capital expenditures as it is assumed that unit separation capital expenditures reflected in the base case are not avoided.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 6.

A. Exhibit A-51 (NJK-2) Revised, page 6, shows the Company's projected capital expenditures for Campbell Units 1 and 2 for the cases in which both Campbell Units 1 and 2 retire on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected capital expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2) Revised, page 6, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 6, line 13, columns (d) and (e), shows that the Company would avoid

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1 \$42,840,000 in capital expenditures at Campbell Unit 1 and \$56,070,000 in capital
2 expenditures at Campbell Unit 2 if both units are retired on May 31, 2024. Exhibit A-51
3 (NJK-2) Revised, page 6, line 13, columns (i) and (j), shows that the Company would avoid
4 \$35,951,000 in capital expenditures at Campbell Unit 1 and \$46,573,000 in capital
5 expenditures at Campbell Unit 2 if both units are retired on May 31, 2025. Exhibit A-51
6 (NJK-2) Revised, page 6, line 26, columns (d) and (e), shows that the Company would
7 avoid \$34,046,000 in capital expenditures at Campbell Unit 1 and \$45,273,000 in capital
8 expenditures at Campbell Unit 2 if both units are retired on May 31, 2026. Exhibit A-51
9 (NJK-2) Revised, page 6, line 26, columns (i) and (j), shows that the Company would avoid
10 \$14,442,000 in capital expenditures at Campbell Unit 1 and \$18,333,000 in capital
11 expenditures at Campbell Unit 2 if both units are retired on May 31, 2028. Campbell Unit
12 3 is not reflected in Exhibit A-51 (NJK-2) Revised, page 5, because the Campbell early
13 retirement cases do not have an impact on the Campbell Unit 3 capital expenditures
14 because the unit separation capital expenditures reflected in the base case are not avoided.

15 **Q. What is the basis for the projected major maintenance expenses in Exhibit A-52**
16 **(NJK-3), page 1, line 1?**

17 A. The major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 1, are those that
18 were used for 2020 in the Company's IRP modeling.

19 **Q. What is the basis for the projected major maintenance expenses in Exhibit A-52**
20 **(NJK-3), page 1, line 2?**

21 A. In 2021, the Company projects to spend:

- 22 • \$3,771,000 at Karn Units 1 and 2, covering 21 projects, none of which exceeds
23 \$700,000;

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- \$1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceeds \$250,000;
- \$11,930,200 at Campbell Units 1 and 2 including:
 - Campbell 2 Generator Overhaul-Rewedge-Collector Ring Replacement (\$3,630,000);
 - Campbell 2 Turbine Inspection and Overhaul (\$2,370,000);
 - Campbell 1 and 2 Periodic Outage Maintenance (\$1,512,000); and
 - Twenty-two additional projects totaling \$4,418,200, with no individual project exceeding \$750,000; and
- \$5,102,729 at Campbell Unit 3 including:
 - Campbell 3 Turbine Valve Inspection (\$1,200,000); and
 - Twenty-two additional projects totaling \$3,902,729, with no individual project exceeding \$715,000.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 3?

A. In 2022, the Company projects to spend:

- \$3,292,000 at Karn Units 1 and 2, covering 19 projects, none of which exceeds \$700,000;
- \$1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceed \$250,000;
- \$3,537,000 at Campbell Units 1 and 2 including:
 - Campbell 1 and 2 Periodic Outage Maintenance (\$1,248,000); and
 - Thirteen additional projects totaling \$2,289,000, with no individual project exceeding \$600,000; and
- \$4,208,040 at Campbell Unit 3 including:
 - Boiler Feed Pump Turbine Inspection (\$1,680,000); and
 - Fourteen additional projects totaling \$2,528,040, with no individual project exceeding \$425,000.

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1 **Q. What is the basis for the projected major maintenance expenses in Exhibit A-52**
2 **(NJK-3), page 1, line 4?**

3 A. In 2023, the Company projects to spend:

- 4 • \$826,000 at Karn Units 1 and 2, covering seven projects, none of which exceeds
5 \$200,000;
- 6 • \$1,000,000 at Karn Units 3 and 4, covering seven projects, none of which
7 exceeds \$250,000;
- 8 • \$2,905,000 at Campbell Units 1 and 2 covering 10 projects, none of which
9 exceeds \$643,667; and
- 10 • \$2,523,970 at Campbell Unit 3 covering 12 projects, none of which exceeds
11 \$425,000.

12 **Q. What is the basis for the projected major maintenance expenses in Exhibit A-52**
13 **(NJK-3), page 1, line 5?**

14 A. In 2024, the Company projects to spend:

- 15 • \$1,000,000 at Karn Units 3 and 4, covering seven projects, none of which
16 exceeds \$250,000;
- 17 • \$3,405,167 at Campbell Units 1 and 2 covering 12 projects, none of which
18 exceeds \$655,167; and
- 19 • \$12,954,250 at Campbell Unit 3 including:
 - 20 ○ Campbell 3 Turbine Overhaul (\$7,931,350);
 - 21 ○ Campbell 3 Boiler Chemical Cleaning (\$1,429,000);
 - 22 ○ Campbell 3 Base Outage Boiler and Critical Maintenance (\$1,000,000);
 - 23 ○ Campbell 3 Periodic Outage Maintenance (\$933,100); and
 - 24 ○ Eight additional projects totaling \$1,660,800, with no individual project
25 exceeding \$430,000.

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1 **Q. What is the basis for the projected major maintenance expenses in Exhibit A-52**
2 **(NJK-3), page 1, line 6?**

3 A. In 2025, the Company projects to spend:

- 4 • \$1,000,000 at Karn Units 3 and 4, covering seven projects, none of which
5 exceeds \$250,000;
- 6 • \$4,569,000 at Campbell Units 1 and 2 including:
 - 7 o Campbell 2 Turbine Valve Inspection (\$1,300,000); and
 - 8 o Seven additional projects totaling \$3,269,000, with no individual project
9 exceeding \$666,667; and
- 10 • \$3,810,600 at Campbell Unit 3 including:
 - 11 o Campbell 3 Turbine Valve Inspection (\$1,200,000);
 - 12 o Campbell 3 Base Outage Boiler and Critical Maintenance (\$1,100,000); and
 - 13 o Six additional projects totaling \$1,410,600, with no individual project
14 exceeding \$450,000.

15 **Q. What is the basis for the projected major maintenance expenses in Exhibit A-52**
16 **(NJK-3), page 1, line 7?**

17 A. In 2026, the Company projects to spend:

- 18 • \$1,000,000 at Karn Units 3 and 4, covering seven projects, none of which
19 exceed \$250,000;
- 20 • \$3,541,000 at Campbell Units 1 and 2 covering nine projects, none of which
21 exceed 678,167; and
- 22 • \$1,660,600 at Campbell Unit 3 covering five projects, none of which exceed
23 500,000.

24 **Q. What is the basis for the projected expenses in Exhibit A-52 (NJK-3), page 1, lines 8**
25 **through 20?**

26 A. In each year from 2027 through 2039 in the base case, the Company projects to incur major
27 maintenance expenses at Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3,

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as shown in Exhibit A-52 (NJK-3), page 1. The number of individual major maintenance projects for Karn Units 3 and 4 is as follows:

- 2027: Seven projects totaling \$1,000,000, with no individual project which exceeds \$250,000;
- 2028: Seven projects totaling \$1,000,000, with no individual project which exceeds \$250,000;
- 2029: Seven projects totaling \$1,000,000, with no individual project which exceeds \$250,000;
- 2030: Seven projects totaling \$800,000, with no individual project which exceeds \$250,000; and
- 2031: Three projects totaling \$250,000, with no individual project which exceeds \$150,000.

The number of individual major maintenance projects for Campbell Unit 1 is as follows:

- 2027: Seven projects totaling \$2,129,667, with no individual project which exceeds \$689,667;
- 2028: Six Projects totaling \$2,351,167, with no individual project which exceeds \$750,000;
- 2029: Six Projects totaling \$1,952,667, with no individual project which exceeds \$712,667;
- 2030: Four Projects totaling \$1,300,000, with no individual project which exceeds \$500,000; and
- 2031: Two Projects totaling \$300,000, with no individual project which exceeds \$200,000.

The number of individual major maintenance projects for Campbell Unit 2 is as follows:

- 2027: Seven projects totaling \$1,423,333, with no individual project which exceeds \$500,000;
- 2028: Six Projects totaling \$1,533,833, with no individual project which exceeds \$500,000;

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- 2029: Six Projects totaling \$3,294,333, which includes:
 - o Campbell 2 Turbine Valve Inspection (\$1,400,000); and
 - o Five Projects totaling \$1,894,333 with no individual project which exceeds \$500,000;
- 2030: Four Projects totaling \$1,204,833, with no individual project which exceeds \$404,833; and
- 2031: Two Projects totaling \$300,000, with no individual project which exceeds \$200,000.

The number of individual major maintenance projects for Campbell Unit 3 is as follows:

- 2027: Nine projects totaling \$2,560,600, with no individual project which exceeds \$500,000;
- 2028: Six Projects totaling \$1,830,600, with no individual project which exceeds \$500,000;
- 2029: Eight Projects totaling \$3,860,600, which includes:
 - o Campbell 3 Turbine Valve Inspection (\$1,300,000);
 - o Campbell 3 Base Outage Boiler and Critical Maintenance (\$1,100,000); and
 - o Six Projects totaling \$1,460,600 with no individual project which exceeds \$500,000;
- 2030: Six Projects totaling \$1,910,600, with no individual project which exceeds \$500,000;
- 2031: Seven Projects totaling \$1,960,600, with no individual project which exceeds \$500,000;
- 2032: Seven Projects totaling \$15,330,600, which includes:
 - o Campbell 3 Turbine Overhaul (\$12,000,000);
 - o Campbell 3 Base Outage Boiler and Critical Maintenance (\$2,000,000); and
 - o Five Projects totaling \$1,330,600 with no individual project which exceeds \$500,000;
- 2033: Eight Projects totaling \$3,860,600, which includes:
 - o Campbell 3 Turbine Valve Inspection (\$1,300,000);

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- o Campbell 3 Base Outage Boiler and Critical Maintenance (\$1,100,000); and
- o Six Projects totaling \$1,460,600 with no individual project which exceeds \$500,000;
- 2034: Five Projects totaling \$1,710,600, with no individual project which exceeds \$500,000;
- 2035: Eight Projects totaling \$2,260,600, with no individual project which exceeds \$500,000;
- 2036: Six Projects totaling \$1,850,600, with no individual project which exceeds \$500,000;
- 2037: Eight Projects totaling \$3,960,600, which includes:
 - o Campbell 3 Turbine Valve Inspection (\$1,400,000);
 - o Campbell 3 Base Outage Boiler and Critical Maintenance (\$1,100,000); and
 - o Six Projects totaling \$1,460,600 with no individual project which exceeds \$500,000;
- 2038: Five Projects totaling \$1,360,600, with no individual project which exceeds \$500,000; and
- 2039: Three Projects totaling \$310,600, with no individual project which exceeds \$110,600.

Q. Please explain Exhibit A-52 (NJK-3), page 2.

A. Exhibit A-52 (NJK-3), page 2, shows the Company's projected major maintenance expenses for Karn Units 3 and 4 for the cases in which Karn Units 3 and 4 retire on May 31, 2023 or May 31, 2025. The projected major maintenance expenses are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-52 (NJK-3), page 2, also shows the difference in major maintenance expenses for each calendar year relative to the base case. Exhibit A-52 (NJK-3), page 2, line 13, column (c), shows that the Company would avoid \$10,050,000 in major maintenance expenses if Karn Units 3 and 4 are retired on May 31, 2023. Exhibit A-52 (NJK-3), page 2, line 13, column (f), shows

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1 that the Company would avoid \$5,700,000 in major maintenance expenses if Karn Units 3
2 and 4 are retired on May 31, 2025.

3 **Q. Please explain Exhibit A-52 (NJK-3), page 3.**

4 A. Exhibit A-52 (NJK-3), page 3, shows the Company's projected major maintenance
5 expenses for Campbell Unit 3 for the cases in which Campbell Unit 3 retires on May 31,
6 2025, or on May 31, 2032. The projected major maintenance expenses are shown for each
7 calendar year from January 1, 2020 through May 31, 2039. Exhibit A-52 (NJK-3), page 3,
8 also shows the difference in major maintenance expenses for each calendar year relative to
9 the base case. Exhibit A-52 (NJK-3), page 3, line 21, column (c), shows that the Company
10 would avoid \$57,555,000 in major maintenance expenses if Campbell Unit 3 is retired on
11 May 31, 2025. Exhibit A-52 (NJK-3), page 3, line 21, column (f), shows that the Company
12 would avoid \$29,984,000 in major maintenance expenses if Campbell Unit 3 is retired on
13 May 31, 2032. Campbell Units 1 and 2 are not reflected in Exhibit A-52 (NJK-3), page 3,
14 because the Campbell Unit 3 early retirement case assumes that Campbell Units 1 and 2
15 retire in a similar timeframe and, therefore, have identical costs to those in the base case
16 through 2026 and 2032.

17 **Q. Please explain Exhibit A-52 (NJK-3), page 4.**

18 A. Exhibit A-52 (NJK-3), page 4, shows the Company's projected major maintenance
19 expenses for Campbell Units 1 and 2 for the cases in which Campbell Unit 1 retires on
20 May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected major
21 maintenance expenses are shown for each calendar year from January 1, 2020 through May
22 31, 2031. Exhibit A-52 (NJK-3), page 4, also shows the difference in major maintenance
23 expenses for each calendar year relative to the base case. Exhibit A-52 (NJK-3), page 4,

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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,

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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

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(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.

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1 A. Exhibit A-53 (NJK-4), page 2, shows the Company's projected base O&M expenses for
2 Karn Units 3 and 4 for the cases in which Karn Units 3 and 4 retire on May 31, 2023 or
3 May 31, 2025. The projected expenses are shown for each calendar year from January 1,
4 2020 through May 31, 2031. Exhibit A-53 (NJK-4), page 2, also shows the difference in
5 expenses for each calendar year relative to the base case. Exhibit A-53 (NJK-4), page 2,
6 column (c), shows that the Company would avoid \$92,202,000 in base O&M expenses if
7 Karn Units 3 and 4 retire on May 31, 2023. Exhibit A-53 (NJK-4), page 2, column (f),
8 shows that the Company would avoid \$73,220,000 in base O&M expenses if Karn Units 3
9 and 4 retire on May 31, 2025.

10 **Q. Please explain Exhibit A-53 (NJK-4), page 3.**

11 A. Exhibit A-53 (NJK-4), page 3, shows the Company's projected base O&M expenses for
12 the Campbell Unit 3 for the cases in which Campbell Unit 3 retires on May 31, 2025, or
13 on May 31, 2032. The projected expenses are shown for each calendar year from
14 January 1, 2020 through May 31, 2039. Exhibit A-53 (NJK-4), page 3, also shows the
15 difference in expenses for each calendar year relative to the base case. Exhibit A-53
16 (NJK-4), page 3, column (c) shows that the Company would avoid \$432,791,000 in base
17 O&M expenses if Campbell Unit 3 retires on May 31, 2025 and Exhibit A-53 (NJK-4),
18 page 3, column (f), shows that the Company would avoid \$232,813,000 in base O&M
19 expenses if Campbell Unit 3 retires on May 31, 2032.

20 **Q. Please explain Exhibit A-53 (NJK-4), pages 4 and 5.**

21 A. Exhibit A-53 (NJK-4), pages 4 and 5, shows the Company's projected base O&M expenses
22 for Campbell Units 1 and 2 for the cases in which Campbell Unit 1 retires on May 31,
23 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected base O&M

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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

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1 expenses are shown for each calendar year from January 1, 2020 through May 31, 2039.
2 Exhibit A-53 (NJK-4), pages 6 and 7, also shows the difference in major maintenance
3 expenses for each calendar year relative to the base case. Exhibit A-53 (NJK-4), page 6,
4 line 21, columns (d), (e), and (f), shows that the Company would avoid \$137,616,000 in
5 base O&M expenses at Campbell Unit 2 and incur incremental base O&M expenses of
6 \$9,857,000 at Campbell Unit 1 and incremental base O&M expenses of \$38,029,000 at
7 Campbell Unit 3 if Campbell Unit 2 is retired on May 31, 2024. Exhibit A-53 (NJK-4),
8 page 6, line 21, columns (j), (k), and (l) show that the Company would avoid \$136,376,000
9 in base O&M expenses at Campbell Unit 2 and incur incremental base O&M expenses of
10 \$8,626,000 at Campbell Unit 1 and incremental base O&M expenses of \$35,919,000 at
11 Campbell Unit 3 if Campbell Unit 2 is retired on May 31, 2025. Exhibit A-53 (NJK-4),
12 page 7, line 21, columns (d), (e), and (f) show that the Company would avoid \$135,176,000
13 in base O&M expenses at Campbell Unit 2 and incur incremental base O&M expenses of
14 \$7,374,000 at Campbell Unit 1 and incremental base O&M expenses of \$33,759,000 at
15 Campbell Unit 3 if Campbell Unit 2 is retired on May 31, 2026. Exhibit A-53 (NJK-4),
16 page 7, line 21, columns (j), (k), and (l), shows that the Company would avoid
17 \$129,417,000 in base O&M expenses at Campbell Unit 2 and incur incremental base O&M
18 expenses of \$4,785,000 at Campbell Unit 1 and incremental base O&M expenses of
19 \$29,319,000 at Campbell Unit 3 if Campbell Unit 2 is retired on May 31, 2028.

20 **Q. Please explain Exhibit A-53 (NJK-4), pages 8 and 9.**

21 A. Exhibit A-53 (NJK-4), pages 8 and 9, shows the Company's projected base O&M expenses
22 for Campbell Units 1 and 2 for the cases in which both Campbell Units 1 and 2 retire on
23 May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected base

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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

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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) Revised.

A. Exhibit A-55 (NJK-6) Revised 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) Revised, page 1.

A. Exhibit A-55 (NJK-6) Revised, 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) Revised, 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)

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1 Revised, page 1, line 22, column (c), shows that the total projected LTSA capital
2 expenditures for DIG are \$~~280,091,000~~148,456,000.

3 **Q. Please explain Exhibit A-55 (NJK-6) Revised, page 2.**

4 A. Exhibit A-55 (NJK-6) Revised, page 2, shows the Company's projected capital
5 expenditures for the new natural gas plants for work that is not covered by the LTSA for
6 Covert and DIG, as well as all projected capital expenditures for Kalamazoo and
7 Livingston, for the period from January 1, 2020 through May 31, 2040. As discussed by
8 Company witness Richard T. Blumenstock, the Company would complete the acquisition
9 of Kalamazoo and Livingston by May 31, 2025, if the Company's PCA is approved.
10 Exhibit A-55 (NJK-6) Revised, page 2, line 22, column (b), shows that the total projected
11 non-LTSA capital expenditures for Covert through 2040 are \$114,887,000, and Exhibit A-
12 55 (NJK-6) Revised, page 2, line 22, column (c), shows that the total projected non-LTSA
13 capital expenditures for DIG, Kalamazoo and Livingston are \$~~151,696,000~~87,185,000.
14 The projected spike in capital expenditures for non-LTSA capital expenditures in 2027
15 reflects work to perform rotor replacement at Covert.

16 **Q. Please explain Exhibit A-55 (NJK-6) Revised, page 3.**

17 A. Exhibit A-55 (NJK-6) Revised, page ~~13~~, shows the Company's projected major
18 maintenance expenses for the new natural gas plants associated with the General Electric
19 and Mitsubishi LTSAs for Covert and DIG for the period from January 1, 2020 through
20 May 31, 2040. Exhibit A-55 (NJK-6) Revised, page 3, line 22, column (b), shows that the
21 total projected LTSA major maintenance expenses for Covert through 2040 are
22 \$69,829,000, and Exhibit A-55 (NJK-6) Revised, page 3, line 22, column (c), shows that
23 the total projected LTSA major maintenance expenses for DIG are \$50,694,000.

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1 **Q. Please explain Exhibit A-55 (NJK-6) Revised, page 4.**

2 A. Exhibit A-55 (NJK-6) Revised, page 4, shows the Company's projected base O&M
3 expenses for the new natural gas plants for work that is not covered by the LTSA for Covert
4 and DIG, as well as the base O&M expenses for Kalamazoo and Livingston, for the period
5 from January 1, 2020 through May 31, 2040. Exhibit A-55 (NJK-6) Revised, page 4, line
6 22, column (b), shows that the total projected non-LTSA base O&M expenses for Covert
7 through 2040 are \$511,184,000, and Exhibit A-55 (NJK-6) Revised, page 4, line 22,
8 column (c), shows that the total projected non-LTSA base O&M expenses for DIG,
9 Kalamazoo, and Livingston are \$543,256,000. The non-LTSA base O&M expenses
10 include both fixed and variable O&M expenses.

11 **SECTION IV: SEPARATION ACTIVITY COSTS**

12 **Q. Please explain Exhibit A-56 (NJK-7).**

13 A. Exhibit A-56 (NJK-7) shows the separation activity costs that the Company would incur in
14 each retirement case. Exhibit A-56 (NJK-7), lines 1 through 9, shows the separation
15 activity costs as they were modeled by the Company for this IRP, based on assumptions
16 made at the time that the modeling was conducted.

17 **Q. What are separation activity costs?**

18 A. Separation activity costs cover those activities that are required to keep the remaining units
19 at a site functioning when other units are retired.

20 **Q. Are there any separation activity costs in the base case?**

21 A. Yes. Exhibit A-56 (NJK-7), lines 1 and 2, shows that unit separation costs were modeled
22 in the base case.

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1 **Q. What separation activity costs did the Company model in the event that Karn Units**
2 **3 and 4 were retired in 2023?**

3 A. As shown in Exhibit A-56 (NJK-7), line 3, if Karn Units 3 and 4 are retired in 2023, the
4 Company's IRP modeling assumes a reduction in the separation activity costs at Karn Unit
5 3 and 4 from \$28,651,000 to \$13,186,000. These costs could potentially be avoided in
6 2022 and 2023 once a decision to retire Karn Units 3 and 4 in 2023 is finalized.

7 **Q. What separation activity costs did the Company model in the event that Campbell**
8 **Unit 3 operated through May 31, 2039?**

9 A. As shown in Exhibit A-56 (NJK-7), line 2, if Campbell Unit 3 operates through May 31,
10 2039, the Company projects that it will incur unit separation costs of \$64,146,000.
11 However, as reflected on lines 7 and 9, a Campbell Unit 3 retirement in 2025 or 2032, if
12 coupled with a Campbell Unit 1 and 2 retirement, would allow the Company to entirely
13 avoid the unit separation costs.

14 **Q. What separation activity cost does the Company expect to actually incur in the event**
15 **that Campbell Units 1 and 2 are retired early?**

16 A. As shown in Exhibit A-56 (NJK-7), lines 4, 5, 6, and 8, the Company is still projecting that
17 it would incur \$64,146,000 in separation activity costs at Campbell Unit 3 in the 2024,
18 2025, 2026, and 2028 Campbell Unit 1 and 2 retirement cases.

19 **Q. Is the Company requesting Commission approval of the separation activity costs for**
20 **the Campbell site in this IRP proceeding?**

21 A. No, the Company is not making such a request in *this* proceeding. The Company developed
22 its projections of \$64,146,000 in separation activity costs based on an external conceptual
23 engineering study of the Campbell Unit 1 and 2 unit separation costs. The Company's base

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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?

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1 A. This separation work is currently underway in order to successfully retire Karn Units 1 and
2 2 on May 31, 2023.

3 **Q. What are the implications of retiring Karn Units 3 and 4 in 2023 on the unit**
4 **separation timeline?**

5 A. Exhibit A-56 (NJK-7), line 3, reflects an extremely aggressive reduction in unit separation
6 capital expenditures for this retirement case in 2022. Due to the potential timing of a final
7 order approving the Company's PCA, it is unrealistic to avoid any unit separation capital
8 expenditures in 2021, and the level of capital expenditures that the Company can avoid in
9 2022 is entirely dependent on when it receives a decision on its PCA. In order to achieve
10 retirement of Karn Units 1 and 2 on May 31, 2023, the Company must continue to proceed
11 with its current separation of these units from Karn Units 3 and 4.

12 **Q. What separation activity costs did the Company model in the event that Campbell**
13 **Units 1 and 2 were retired in 2024, 2025, 2028 or 2031?**

14 A. Exhibit A-56 (NJK-7), lines 4, 5, 6, and 8, shows the costs that the Company's IRP
15 modeling assumes would be incurred at Campbell Unit 3 if both Campbell Units 1 and 2
16 were retired in 2024, 2025, 2026, 2028. If only one of the two units is retired, the separation
17 activity costs would not be incurred at Campbell Unit 3 until 2028 as modeled in the base
18 case assuming that Campbell Unit 3 operates through 2039. However, if Campbell Unit 3
19 is retired in 2025 or 2032, and its retirement is coupled with a Campbell Unit 1 and 2
20 retirement, the unit separation costs can be avoided. The separation activity costs at
21 Campbell Unit 3 in these bases would be an estimated \$64,146,000, incurred from 2028
22 through 2031, to prepare Campbell Unit 3 to operate on a standalone basis once Campbell
23 Units 1 and 2 are retired.

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1 **Q. What separation activity costs would the Company expect to actually incur in the**
2 **event that Campbell Units 1 and 2 are retired early?**

3 A. As shown in Exhibit A-56 (NJK-7), lines 4, 5, 6, and 8, the Company is still projecting that
4 it would incur an estimated \$64,146,000 in separation activity costs at Campbell Unit 3
5 that were projected in the IRP modeling. As previously discussed, these costs can be
6 avoided with an early Campbell Unit 3 retirement case.

7 **Q. If Campbell Units 1 and 2 were retired, what separation activity work would the**
8 **Company plan to complete?**

9 A. In order to allow Campbell Unit 3 to remain operating after the retirement of Campbell
10 Units 1 and 2, the Company would leave the structure housing Campbell Units 1 and 2 in
11 place, with its tripper deck remaining in service. All fuel handling equipment would have
12 to be rerouted and fuel handling, the tripper deck, and ventilation and heating equipment
13 at the site would have to be repowered from Campbell Unit 3. The fuel handling conveyor
14 reroute work constitutes a large portion of the costs reflected in Exhibit A-56 (NJK-7),
15 lines 4, 5, 6, and 8. Using this approach would involve fewer upfront costs and would be
16 logistically simpler than building new fuel handling equipment. Leaving the structure
17 housing Campbell Units 1 and 2 standing would require the Company to incur some
18 incremental major maintenance expenses, as discussed later in my direct testimony.
19 Because the structure would remain standing, Campbell Units 1 and 2 would not formally
20 enter the cold and dark period, and it would likely be difficult to pursue any redevelopment
21 opportunities at the site.

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SECTION V: UNAVOIDABLE, AVOIDABLE, AND INCREMENTAL COSTS

Q. Please explain Exhibit A-57 (NJK-8) Revised.

A. Exhibit A-57 (NJK-8) Revised 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

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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) Revised.

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) Revised.

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) Revised, page 2, lines 4 and 8, for the 2024 retirement case. In Exhibit A-51 (NJK-2) Revised: (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

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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 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,

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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.

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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.

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

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

12 **Q. What are the Company's expectations regarding ROR and NEV for its coal-fired**
13 **generating units?**

14 A. As presented on Exhibit A-59 (NJK-10), page 1, the Company has projected a steady
15 decline in ROR through retirement for Campbell Units 1 and 2 and Karn Units 1 and 2. As
16 previously discussed, the Company's projections of ROR take into account the projected
17 unit investment and, given the current retirement dates for these units, investments targeted
18 at improving ROR are generally uneconomic and not likely to result in providing
19 incremental customer value. As a result, it is likely that the NEV for these units will also
20 decline slightly as they move closer to retirement.

21 **Q. Please explain Exhibit A-59 (NJK-10), page 2.**

22 A. Exhibit A-59 (NJK-10), page 2, illustrates the historic Equivalent Forced Outage Rate
23 Demand ("EFOR_d") of the Company's generation units at the Campbell and Karn sites.

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1 **Q. Please define EFOR_d.**

2 A. EFOR_d represents the hours of unit failure (Forced Outage Hours demand + Equivalent
3 Forced Derate Hours demand), given as a percentage of the total hours of unit availability
4 (Service Hours + Forced Outage Hours demand + Equivalent Forced Derate Hours During
5 Reserve Shutdown).

6 **Q. What does the ROR and EFOR_d information in Exhibit A-59 (NJK-10) indicate about**
7 **the condition of the existing equipment at Campbell Units 1 and 2 and Karn Units 1**
8 **and 2?**

9 A. Exhibit A-59 (NJK-10) indicates that Campbell Units 1 and 2 have generally performed
10 more reliably than Karn Units 1 and 2 as measured by ROR and EFOR_d, and the ROR of
11 Campbell Units 1 and 2 are projected to continue demonstrating better reliability than Karn
12 Units 1 and 2 in future years leading up to retirement. This indicates that the condition of
13 existing equipment at Campbell Units 1 and 2 is generally better than that at Karn Units 1
14 and 2.

15 **Q. Are there other measures used to inform operational and financial decisions in order**
16 **to optimize the customer value of the generating unit?**

17 A. Investments made to improve reliable operations at generating units can provide capacity
18 value as well as energy value. The Company is required by the Midcontinent Independent
19 System Operation, Inc. ("MISO") to secure enough capacity on an annual basis to cover
20 all of its load, plus a reserve margin. All of the Company's units provide some capacity
21 towards meeting this obligation and EFOR_d is a measure which factors into the
22 determination of that capacity.

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1 **Q. Please explain Confidential Exhibit A-60 (NJK-11), page 1.**

2 A. Confidential Exhibit A-60 (NJK-11), page 1, illustrates the projected heat rates for
3 Campbell Units 1 and 2 in the base case and the various retirement cases.

4 **Q. Please define heat rate.**

5 A. The heat rate or efficiency of a unit is the amount of energy used by an electrical generator
6 to produce one kilowatt-hour (kWh) of electricity, represented in BTU/kWh.

7 **Q. How have the changes in projected investment in the various retirement cases for**
8 **Campbell Unit 1 impacted its projected heat rates?**

9 A. As reflected on Confidential Exhibit A-60 (NJK-11), lines 1-12, the heat rate for Campbell
10 Unit 1 through 2023 is identical in the base case and each retirement case. However, in
11 the 2024, 2025, and 2026 Campbell Unit 1 retirement cases, the heat rate degrades
12 (increases) in 2024 due to the elimination of the project to replace the air preheater baskets
13 and seals in 2023 and 2024. As such, only the base case and 2028 retirement case reflect
14 a heat rate improvement in 2024 and beyond. No other projects in the base case provide
15 heat rate improvement.

16 **Q. How have the changes in projected investment in the various retirement cases for**
17 **Campbell Unit 2 impacted its projected heat rates?**

18 A. As reflected on Confidential Exhibit A-60 (NJK-11), lines 13-24, the heat rate for
19 Campbell Unit 2 through 2031 is identical in the base case and each retirement case. The
20 reason for this is that there are no major Campbell Unit 2 projects with heat rate effects
21 after the Turbine/Generator work and air heater seal replacement work in 2021. As such,
22 the heat rate degradation is the same for all cases.

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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

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1 seek positions elsewhere in the Company, or externally. In that circumstance, it could
2 become difficult for the units to be safely operated through the retirement date. When the
3 Company retired the Classic 7 in 2016, and made plans to retire Karn Units 1 and 2 in
4 2023, the Company was able to mitigate these employee retention risks because it had time
5 to develop a transition plan that gave employees needed confidence to remain at those units
6 through the closure date, knowing that they would likely be able to move to other positions
7 within the Company afterward. However, with the retirement of all remaining coal units,
8 the difficulty of this task has significantly increased. Further, the Company has observed
9 situations involving other utilities in which the retirement of a generation plant was made
10 more difficult by less than adequate human resource management and planning. For
11 example, there have been situations at other utilities in which plant employees were not
12 provided any kind of post-closure transition plan, meaning those employees were liable to
13 lose their jobs, resulting in low morale and delays in the retirement of the plant. By having
14 an effective transition plan in place for employees, the Company can effectively mitigate
15 these risks.

16 **Q. Is the Company considering environmental risks in retiring the Campbell site?**

17 A. Yes. When the units are retired, the Company will have to bring the units into compliance
18 with environmental regulations. This will include vacuuming all ash, draining boilers, and
19 removing all oil from the machinery. The Company will ensure that nothing is left at the
20 site that may leak and release pollution into the environment. In performing this
21 environmental work, the Company will ensure that it does not, and will not, exceed any
22 regulatory limits on emissions into local waterways throughout the prolonged cold and dark
23 period, which will require sufficient time during the cold and dark period. If the Company

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1 does not have sufficient time to do this cleaning, it runs the risk of significantly increased
2 clean-up costs in order to ensure that the Company does not violate emissions limits and
3 completes all necessary clean-up work. In addition to the clean-up work itself, the
4 Company will also need to address the coal pile. The Company plans to burn the coal pile
5 down in the final weeks of the units' operation, so that as little coal remains onsite as
6 possible. The Company will evaluate remediation of the land on which the coal pile sits to
7 determine if that land can be redeveloped for other purposes.

8 **Q. Is the Company considering risks related to the future use of the site?**

9 A. Yes. The Company has recent experience in evaluating future use of a retired generation
10 unit site, having done so when the Classic 7 were retired and currently doing so for the
11 Karn site. During the Classic 7 retirement process, the Company evaluated various future
12 use options for those sites, and Consumers Energy had enough time in that process to
13 effectively study the divestment of those sites and opportunities to divest to third parties
14 who would also manage facility demolition and redevelopment, mitigating the risk of
15 unnecessarily high costs and optimizing customer value since a specialized firm would
16 manage demolition and redevelopment instead of the Company doing so directly. In the
17 case of Campbell site, the Company would also need time to study different future use
18 options for the site, and to vet different options for both Company-managed demolition
19 and redevelopment and for divestment to a third-party firm to do that work.

20 **Q. Are there future use risks related to the local community?**

21 A. Impacts to the community when the Campbell site retires are discussed later in my direct
22 testimony. At a high level, the retirement will impact the community's tax base and
23 employment base. The Company is committed to assisting in redevelopment of the site to

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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.

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1 **Q. Are there any risks that would result in Campbell site being required to be operated**
2 **beyond 2025?**

3 A. Yes. To retire a generation unit, the Company must get approval from MISO. MISO will
4 study the Company's retirement proposal to ensure that it does not create transmission
5 reliability concerns, particularly related to maintaining voltage on the transmission system.
6 If MISO finds that transmission reliability concerns will exist, MISO may require one or
7 more of the units to remain in operation until such time that a solution is found and
8 completed to mitigate the reliability problem. As part of its stakeholder process, MISO
9 would consider solutions, such as: (i) re-dispatch or reconfiguration of the transmission
10 system; (ii) special protection schemes; (iii) contracted demand response; (iv) new or
11 expanded generation elsewhere on the system; and (v) transmission expansion.

12 **Q. What would happen if MISO does require one or both units to remain in operation?**

13 A. If MISO makes such a determination, it would designate the unit or units as a System
14 Support Resource ("SSR"). When a unit becomes an SSR, MISO ensures that the unit fully
15 recovers its ongoing operating costs by assigning those costs to affected MISO
16 transmission customers through MISO's Federal Energy Regulatory
17 Commission-regulated transmission rates.

18 **SECTION VIII: TAX, COMMUNITY, AND EMPLOYEE IMPACTS OF EARLY**
19 **RETIREMENT**

20 **Karn Units 3 and 4**

22 **Q. What is the tax impact of Karn Units 3 and 4?**

23 A. The Company pays property taxes on Karn Units 3 and 4 that fund local governmental
24 services provided by Hampton Township and Bay County. The units' 2020 taxable value
25 was \$25.6 million, which was approximately 0.87% of the total taxable value in Bay

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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

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1 in more detail in a future-use study. The transition plan also identifies economic
2 weaknesses in the area and potential threats to redevelopment.

3 **Q. Please describe the results of the Company's transition planning for retirement of the**
4 **Classic 7.**

5 A. The Company's transition plans for the Classic 7 focused on a smooth transition through
6 open communication and regional sustainable vision alignment. The performance of future
7 use studies along with collaboration with community stakeholders were critical to the
8 Classic 7 decommissioning process. The Company's community partners included
9 residents, government officials, state elected officials, economic development
10 organizations, vendors, state agencies, and employees affected by the closure.

11 **Q. How has the Company's community engagement resulted in success for the affected**
12 **communities?**

13 A. The Company's community engagement process at its Cobb plant, which is located at the
14 Port of Muskegon, helped regional community leaders find new solutions to market and
15 manage the port and re-imagine the potential for Muskegon Lake. Current plans include
16 conversion of the area into a deep-water marine terminal. Similarly, the Company's
17 stakeholder engagement process associated with the closing, near-complete demolition and
18 active redevelopment of the Whiting plant will result in a site which is ideal for
19 manufacturing and warehousing based upon its extensive logistical advantages such as rail
20 and direct access to I-75.

21 **Q. Please explain the community communication plan for Karn Units 3 and 4.**

22 A. The Company began implementation of the communication plan as soon as the Company
23 announced that it planned to retire Karn Units 3 and 4; this communication is the key first

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1 step in implementing the community transition plan, beginning the process of engaging
2 stakeholders. Immediately prior to this filing, the Company notified all affected
3 stakeholders of the retirement proposal, with the stakeholders including employees, local
4 governments, community business leaders, local media, and local community
5 organizations. Stakeholders also include State of Michigan government agencies and state
6 and federal elected officials. The Company will be in communication throughout the
7 retirement process with community stakeholders. All identified stakeholders will receive
8 relevant communication at regular intervals from assigned Company representatives.

9 **Q. Please explain the future-use study process for Karn Units 3 and 4.**

10 A. The Company has been conducting a future-use study as part of its process for planning to
11 retire Karn Units 1 and 2. These studies will consider environmental issues and local
12 economic issues, such as real estate markets and demographics, and analyzed potential
13 redevelopment options for each site. The retirement of all four Karn units in 2023 will
14 un-restrain potential redevelopment options for the Karn site which is adjacent to the
15 formerly retired Weadock site. Previous redevelopment options for the Weadock site were
16 limited to reuse by the Company for other purposes. The Company will consider options
17 for private redevelopment, as the retirement of Karn Units 1, 2, 3, & 4 may make more of
18 the site, such as the port facilities, available for redevelopment.

19 **Q. How will the retirement of Karn Units 3 and 4 in 2023 affect Company employees?**

20 A. The employees that support the operation of Karn Units 1 and 2 as well as Karn Units 3
21 and 4 are Karn site employees. As such, all of the employees that directly support day-to-
22 day facility operation were included in the Company's retention and separation program
23 which was established to support the retirement of Karn Units 1 and 2 in 2023. The

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Company continues to be committed to ensuring a smooth transition for the Karn employees as the decommissioning process for the Karn site is implemented.

Campbell Units 1, 2, and 3

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

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1 be closely coordinated with a communications strategy that will ensure that all relevant
2 stakeholders are properly informed about the plan. Additionally, the Company plans to
3 complete a detailed future-use study to analyze specific potential opportunities to redevelop
4 the Campbell site.

5 **Q. Please explain the community transition plan.**

6 A. The community transition plan for Campbell Units 1, 2, and 3 will be similar in intent to
7 community transition plans that the Company developed for the retirement of the Karn
8 Units 1 and 2 and the Classic 7. The transition plan will identify and describe the economic
9 strengths of Ottawa County and advantages of the Campbell site for future redevelopment,
10 which would be explored in more detail in a future-use study. The transition plan also
11 identifies economic weaknesses in the area, and potential threats to redevelopment.

12 **Q. Please explain the community communication plan.**

13 A. The Company began implementation of the communication plan as soon as the Company
14 announced that it planned to retire Campbell Units 1, 2, and 3; this communication is the
15 key first step in implementing the community transition plan, beginning the process of
16 engaging stakeholders. Immediately prior to this filing, the Company notified all affected
17 stakeholders of the retirement proposal, with the stakeholders including employees, local
18 governments, community business leaders, local media, and local community
19 organizations. Stakeholders also include State of Michigan government agencies and state
20 and federal elected officials. The Company will be in communication throughout the
21 retirement process with community stakeholders. All identified stakeholders will receive
22 relevant communication at regular intervals from assigned Company representatives.

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1 **Q. Please explain the future-use study process.**

2 A. The Company previously developed future-use studies as part of its process for retiring the
3 Classic 7 and, as previously mentioned, is in the process of conducting a future use study
4 for the Karn site. These studies considered environmental issues and local economic
5 issues, such as real estate markets and demographics, and analyzed potential
6 redevelopment options for each site. Because the Company intends to retire the Campbell
7 site in its entirety, the potential redevelopment options are less restrained than if only one
8 or two of the three units were retired.

9 **Q. How many employees does the Company currently have at the Campbell site?**

10 A. The Campbell site currently has 405 employees at the Campbell site, 313 of whom directly
11 support day-to-day facility operation, with representatives of the Company's Generation
12 Operations, Generation Engineering, Environmental, and other groups. Within the total
13 number of 313 employees that directly support day-to-day facility operation, 214
14 employees are operations, maintenance, and construction ("OM&C") employees, 75 are
15 exempt employees, and 24 are non-exempt employees. Employees in executive, manager
16 and supervisor, professional, and outside sales positions are considered by the Company to
17 be *exempt* from the Fair Labor Standards Act's minimum wage, overtime pay, and certain
18 record-keeping requirements, and are considered at-will employees. Employees who work
19 as technicians, office and clerical staff, and administrative support are considered *not to be*
20 *exempt* from those requirements. OM&C employees at the Campbell site are represented
21 by the Utility Workers Union of America ("UWUA").

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1 **Q. How will the retirement of the Campbell site in 2025 affect Company employees?**

2 A. The Company is committed to ensuring a smooth transition for employees as the
3 decommissioning process for Campbell is implemented. The Company will use regular
4 and transparent internal communications with its employees to ensure that employees are
5 informed about the Company's plans. The Company will leverage the lessons it learned
6 from its successful experience in retiring the Classic 7 and planning for retirement of Karn
7 Units 1 and 2 in developing a retention and separation plan to govern how employees are
8 treated during the decommissioning process of Campbell Units.

9 **Q. What is the Company's intended timing for its retention and separation plan?**

10 A. Once a retirement date for the Campbell site is established, pursuant to an MPSC order in
11 this case, the Company will implement a retention plan that takes effect 40 months prior to
12 that retirement date. For example, if the Campbell Units are scheduled to complete their
13 cold and dark activities by October 31, 2025, then the retention plan would go into effect
14 on July 1, 2022. The retention plan for OM&C employees was previously negotiated with
15 the UWUA and approved by Company leadership; retention plans for other classifications
16 of employees have been developed by the Company, as well. The separation plan exists
17 within current Company agreements and policies and would take effect when the Campbell
18 site retires.

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

20 A. The Company has a strong interest in keeping qualified employees working at the
21 Campbell site through the site's retirement date to ensure safe and reliable operations.
22 Once a retirement date for the Campbell site is confirmed, some employees may seek
23 employment at other Company locations or outside of the Company; meanwhile, hiring

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1 new employees at the Campbell site will become more difficult given the short remaining
2 lifespan of the units, plus the training time necessary for any new hires is challenging.
3 Using the best practices that the Company employed in retiring the Classic 7 and planning
4 for the retirement of Karn Units 1 and 2, the Company plans to offer retention bonuses to
5 all impacted employees who stay at the Campbell site for the entire 40-month period noted
6 above.

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

8 A. When the Campbell site is retired, the Company plans to follow the terms of the collective
9 bargaining agreement for OM&C employees represented by the UWUA and the terms of
10 the employee handbook policy and separation plan for non-represented exempt and non-
11 exempt employees. The structure and amount of the severance offers will vary based on
12 employee salary and classification due to differences in the terms of the separation plan
13 covering non-represented employees and the bargaining agreement for
14 UWUA-represented employees. In the event that exempt or non-exempt employees cannot
15 find placement with the Company within 30 miles from their current location, they will be
16 offered involuntary severance in accordance with the terms of the Company's Salaried
17 Separation Plan. The Company's Working Agreement with the UWUA governs separation
18 for OM&C employees who elect to leave the Company rather than accept a new position;
19 relocation policies for OM&C employees are explained in further detail below.

20 **Q. What are the estimated costs of the retention and separation plan?**

21 A. Based on current employment levels and demographics, the Company estimates the costs
22 of this retention program, including estimated severance and moving cost, is \$60 million if
23 all employees qualify for the retention bonus and all retirement-eligible employees accept

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1 a severance offer. It is the Company's intent to find placements for as many employees as
2 possible, thus mitigating the cost of separations.

3 **Q. Is the Company requesting recovery of the retention incentive costs in this**
4 **proceeding?**

5 A. Yes. As discussed by Company Witness Jason R. Coker, the Company is requesting the
6 expense recognition to be deferred as a regulatory asset until such time that the expenses
7 are recovered in rates.

8 **Q. What is the possible impact to affected employees at the Campbell site?**

9 A. The Company expects that approximately 313 employees will be needed to continue
10 operation of the Campbell site until its proposed retirement in 2025. The rest of the
11 employees will be covered by the policy relevant to their classification. The Working
12 Agreement covering OM&C employees guarantees all eligible OM&C employees a
13 position at their current respective wage within 60 miles of the Campbell site. It is the
14 Company's intent that all exempt and non-exempt employees, who desire to retain
15 employment with the Company, will be offered another position. However, in the event
16 that exempt or non-exempt employees cannot find placement within the Company, they
17 will be offered involuntary severance in accordance with the terms of the Salaried
18 Separation Plan. The Company has 7 locations within 60 miles of the Campbell site.

19 **Q. What is the Company's recent history with managing employee impacts following the**
20 **retirement of a coal-fired power plant?**

21 A. Following the retirement of the Classic 7 in 2016, all Company employees who desired to
22 continue employment with the Company were able to do so. The Company believes that
23 this demonstrates the Company's commitment to its employees. The retirement of the

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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.

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1 **Q. To minimize retraining, could the Company relocate employees from the Campbell**
2 **site to the Covert site?**

3 A. Yes. The Covert site is within 60 miles of the Campbell site. While gas and coal generating
4 plants are operated differently, there are many similarities with respect to maintenance
5 which could allow for a relatively smooth transition for some Campbell employees. To
6 the extent that employees relocate to locations which are not within a 60 mile radius of the
7 Campbell site, the Company's Working Agreement covering OM&C employees allows
8 those employees to receive Company-paid moving expenses if they accept a position more
9 than 60 miles away, and the Company is providing an additional relocation incentive for
10 employees moving more than 60 miles.

11 **Q. Does this conclude your direct testimony?**

12 A. Yes.

Attachment FF

NPDES Permit - FINAL_CECO -
J H Campbell Power Plant

PERMIT NO. MI0001422



STATE OF MICHIGAN
DEPARTMENT OF ENVIRONMENT, GREAT LAKES, AND ENERGY

**AUTHORIZATION TO DISCHARGE UNDER THE
NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM**

In compliance with the provisions of the Federal Water Pollution Control Act, 33 U.S.C., Section 1251 *et seq.*, as amended; Part 31, Water Resources Protection, of the Natural Resources and Environmental Protection Act, 1994 PA 451, as amended (NREPA); Part 41, Sewerage Systems, of the NREPA; and Michigan Executive Order 2019-06,

Consumers Energy Company
One Energy Plaza
Jackson, MI 49201

is authorized to discharge from the **Consumers Energy Company, J. H. Campbell Power Plant** located at

17000 Croswell St.
West Olive, MI 49460

designated as **CECO-J H Campbell Power Plt**

to the receiving waters named Lake Michigan and the Pigeon River in accordance with effluent limitations, monitoring requirements, and other conditions set forth in this permit.

This permit is based on a complete application submitted on March 22, 2016, as amended through September 1, 2016; and a complete modification request submitted on January 11, 2021.

This permit originally took effect on June 1, 2018. This modified permit takes effect on October 1, 2021. The provisions of this permit are severable. After notice and opportunity for a hearing, this permit may be modified, suspended, or revoked in whole or in part during its term in accordance with applicable laws and rules. On its original effective date, the permit superseded National Pollutant Discharge Elimination System (NPDES) Permit No. MI0001422 (expiring October 1, 2016).

This permit and the authorization to discharge shall expire at midnight on **October 1, 2022**. In order to receive authorization to discharge beyond the date of expiration, the permittee shall submit an application that contains such information, forms, and fees as are required by the Michigan Department of Environment, Great Lakes, and Energy (Department) by **April 4, 2022**.

Issued: May 29, 2018. Modified (major) September 30, 2021.

Original signed by Christine Alexander
Christine Alexander, Manager
Permits Section
Water Resources Division

PERMIT FEE REQUIREMENTS

In accordance with Section 324.3120 of the NREPA, the permittee shall make payment of an annual permit fee to the Department for each October 1 the permit is in effect regardless of occurrence of discharge. The permittee shall submit the fee in response to the Department's annual notice. Payment may be made electronically via the Department's MiWaters system. The MiWaters website is located at <https://miwaters.deq.state.mi.us>. Payment shall be submitted or postmarked by January 15 for notices mailed by December 1. Payment shall be submitted or postmarked no later than 45 days after receiving the notice for notices mailed after December 1.

Annual Permit Fee Classification: Industrial-Commercial Major

In accordance with Section 324.3118 of the NREPA, the permittee shall make payment of an annual storm water fee to the Department for each January 1 the permit is in effect regardless of occurrence of discharge. The permittee shall submit the fee in response to the Department's annual notice. Payment may be made electronically via the Department's MiWaters system. The MiWaters website is located at <https://miwaters.deq.state.mi.us>. Payment shall be submitted or postmarked by March 15 for notices mailed by February 1. Payment shall be submitted or postmarked no later than 45 days after receiving the notice for notices mailed after February 1.

CONTACT INFORMATION

Unless specified otherwise, all contact with the Department required by this permit shall be made to the Grand Rapids District Office of the Water Resources Division. The Grand Rapids District Office is located at State Office Building, Fifth Floor, 350 Ottawa Ave NW, Unit 10, Grand Rapids, Michigan, 49503-2341, Telephone: 616-356-0500, Fax: 616-356-0202.

CONTESTED CASE INFORMATION

Any person who is aggrieved by this permit may file a sworn petition with the Michigan Administrative Hearing System within the Michigan Department of Licensing and Regulatory Affairs, c/o the Michigan Department of Environment, Great Lakes, and Energy, setting forth the conditions of the permit which are being challenged and specifying the grounds for the challenge. The Department of Licensing and Regulatory Affairs may reject any petition filed more than 60 days after issuance as being untimely.

PART I

Section A. Limitations and Monitoring Requirements

1. Effluent Limitations, Monitoring Point 001A

During the period beginning on the effective date of this permit and lasting until the expiration date of this permit, the permittee is authorized to discharge a maximum of 984.841 MGD of noncontact cooling water; intake screen backwash; low volume wastewater, which includes but is not limited to: boiler blowdown, boiler drainage, recirculating house service water, laboratory and sampling streams, and water from floor drains; bottom ash transport water; chemical metal cleaning wastewater; coal pile runoff; storm water; leachate retention pond water; reverse osmosis backwash and reject water; and groundwater seepage from ash ponds and the recirculation pond from Monitoring Point 001A through Outfall 001. Outfall 001 discharges to Lake Michigan at Latitude 42.91164, Longitude -86.21269. Such discharge shall be limited and monitored by the permittee as specified below.

<u>Parameter</u>	<u>Maximum Limits for Quantity or Loading</u>			<u>Maximum Limits for Quality or Concentration</u>			<u>Monitoring Frequency</u>	<u>Sample Type</u>
	<u>Monthly</u>	<u>Daily</u>	<u>Units</u>	<u>Monthly</u>	<u>Daily</u>	<u>Units</u>		
Flow	(report)	(report)	MGD	---	---	---	Daily	Report Total Daily Flow
Total Residual Oxidant (TRO) – See Part I.A.1.g. <u>During Chlorination – No Bromine Use</u>								
Total Residual Chlorine (TRC) Discharge Time			---	---	(report)	min/day	Daily	Report Total Discharge Time
Continuous (greater than 160 min/day)	---	---	---	---	38	ug/l	Daily	Grab
Intermittent (less than/equal to 160 min/day)				<u>Daily Average</u> 200	<u>Instantaneous Maximum</u> 300	ug/l	Daily	Grab
<u>During Bromination – Alone or With Chlorine</u>								
Intermittent (less than/equal to 120 min/day)				(report)	50	ug/l	Daily	Grab
					<u>Maximum Daily</u>			
TRO Discharge Time		---	---	---	120	min/day	Daily	Report Total Discharge Time
Total Phosphorus (as P)	---	(report)	lbs/day	---	(report)	mg/l	Quarterly	Grab
Total Copper, see Part I.A.1.i.	---	---	---	---	(report)	mg/l	Daily	Grab
Total Iron, see Part I.A.1.i.	---	---	---	---	(report)	mg/l	Daily	Grab
EVAC (as amine)	---	---	---	---	78	ug/l	Every 2 Hrs During Discharge	Grab
Temperature								
Intake (Unit 3 intake)	---	---	---	(report)	(report)	°F	Daily	Continuous
Discharge	---	---	---	(report)	(report)	°F	Daily	Continuous
Outfall Observation	(report)	---	---	---	---	---	5X Weekly	Visual

PART I**Section A. Limitations and Monitoring Requirements**

<u>Parameter</u>	<u>Maximum Limits for Quantity or Loading</u>			<u>Maximum Limits for Quality or Concentration</u>			<u>Monitoring Frequency</u>	<u>Sample Type</u>
	<u>Monthly</u>	<u>Daily</u>	<u>Units</u>	<u>Monthly</u>	<u>Daily</u>	<u>Units</u>		
				<u>Minimum Daily</u>				
pH	---	---	---	6.5	9.0	S.U.	2X Monthly	Grab

- a. **Narrative Standard**
The receiving water shall contain no turbidity, color, oil films, floating solids, foams, settleable solids, suspended solids, or deposits as a result of this discharge in unnatural quantities which are or may become injurious to any designated use.
- b. **Monitoring Location**
Samples, measurements, and observations taken in compliance with the monitoring requirements above shall be taken prior to discharge to Lake Michigan. Intake temperature monitoring shall be taken at the Unit 3 intake.
- c. **Outfall Observation**
Outfall observation shall be reported as "yes" or "no." The permittee shall report yes if this requirement was completed and no if this requirement was not completed. Any unusual characteristics of the discharge (i.e., unnatural turbidity, color, oil film, floating solids, foams, settleable solids, suspended solids, or deposits) shall be reported within 24 hours to the Department followed with a written report within 5 days detailing the findings of the investigation and the steps taken to correct the condition.
- d. **Quarterly Monitoring**
Quarterly samples shall be taken during the months of January, April, July, and October. If the facility does not discharge during these months, the permittee shall sample the next discharge occurring during the period in question. If the facility does not discharge during the period in question, a sample is not required for that period. For any month in which a sample is not taken, the permittee shall enter "*"G" on the Discharge Monitoring Report (DMR).
- e. **Water Treatment Additives**
This permit does not authorize the discharge of water treatment additives without approval. Approval of water treatment additives is authorized under separate correspondence. Water treatment additives include any material that is added to water used at the facility or to a wastewater generated by the facility to condition or treat the water. In the event a permittee proposes to discharge water treatment additives, including an increased discharge concentration of a previously approved water treatment additive, the permittee shall submit a request for approval in accordance with Part I.A.6. of this permit.
- f. **Analytical Methods and Quantification Levels for Total Phosphorus and Total Copper**
The sampling procedures, preservation and handling, and analytical protocol for compliance monitoring for Total Phosphorus and Total Copper shall be in accordance with Part II.B.2. of this permit. The quantification level for Total Phosphorus and Total Copper, shall be 10 ug/l and 1.0 ug/l, respectively, unless a higher level is appropriate because of sample matrix interference. Justification for higher quantification levels shall be submitted to the Department within 30 days of such determination. Upon approval from the Department, the permittee may use alternate analytical methods (for parameters with methods specified in Title 40 of the Code of Federal Regulations (CFR), Part 136, the alternate methods are restricted to those listed in 40 CFR, Part 136).

PART I

Section A. Limitations and Monitoring Requirements

- g. Total Residual Oxidant (Chlorine and Bromine) Requirements
Total Residual Oxidant (TRO) shall be analyzed in accordance with Part II.B.2. of this permit. TRO monitoring is only required during periods of chlorine or bromine use and subsequent discharge. The limitations specified in Part I.A.1. for the intermittent discharge of chlorine alone apply only when the discharge of chlorine alone is less than or equal to 160 minutes per day, otherwise the limitations for continuous discharge of chlorine alone apply. Authorization to discharge bromine alone or with chlorine is limited to 120 minutes per day at the limitations specified in Part I.A.1., with the additional requirement that any discharge of chlorine is further restricted to a concurrent discharge with bromine (no additional discharge of chlorine is authorized for that day).

During the intermittent discharge of chlorine without bromine ("During Chlorination – No Bromine Use"), the daily average concentration reported for TRC shall be the average of the individual analytical results of a minimum of three (3) grab samples collected at equal intervals during a chlorine discharge event, with the additional limitation that no single sample may exceed 300 ug/l.

During the intermittent discharge of bromine alone or with chlorine ("During Bromination – Alone or With Chlorine"), the daily average concentration reported for TRO shall be the average of the individual analytical results of a minimum of three (3) grab samples collected at equal intervals during a bromine, or bromine plus chlorine, discharge event, with the limitation that no single sample may exceed 50 ug/l of TRO.

The permittee shall enter "*"G" on the Discharge Monitoring Report for the TRO discharge modes not being used.

The permittee may use dehalogenation techniques to achieve the applicable TRO limitations, using sodium thiosulfate, sodium sulfite, sodium bisulfite, or other dehalogenating reagents approved by the Department. The quantity of the reagent(s) used shall be limited to 0.6 times the stoichiometric amount of TRO for sodium thiosulfate, 1.5 times the stoichiometric amount of TRO for sodium bisulfite, and 1.8 times the stoichiometric amount of TRO for sodium sulfite. The TRO samples taken to determine the amount of each chemical to add shall be taken upstream of dehalogenation.

- h. Zebra Mussel Control Requirements
The discharge of EVAC (as amine) is restricted to no more than six (6) times per year, for no more than 12 hours per discharge event. The permittee shall notify the Department at least one (1) week prior to each discharge.

The sampling procedure, preservation and handling, and analytical protocol for compliance monitoring for EVAC (as amine) shall be in accordance with the Acid Orange Method. The quantification level shall not exceed 50 ug/l for EVAC (as amine), unless higher levels are appropriate because of sample matrix interference. Justification for higher quantification levels shall be submitted to the Department within 30 days of such determination. Other methods may be used upon approval from the Department. The highest value measured during the discharge event shall be reported. If the concentration in all samples is less than the quantification level, report "<" the quantification level used by the analyzing laboratory on the DMR.

- i. Total Copper and Total Iron Monitoring
The monitoring requirements for total copper and total iron apply only when a discharge from the chemical treatment facility occurs through Monitoring Point 001A.
- j. Temperature Monitoring
When the continuous temperature monitoring system is inoperative, the effluent daily maximum temperature may be reported on a single daily reading.

PART I**Section A. Limitations and Monitoring Requirements**

- k. **Acid Cleaning**
The periodic use of Muriatic acid for cleaning sodium hypochlorite injection systems nozzles is approved.
- l. **Power Plants – Polychlorinated Biphenyls (PCB) Prohibition**
The permittee shall not discharge any PCBs to the receiving waters of the state of Michigan as a result of plant operations.

2. Effluent Limitations, Monitoring Point 001B (Ash Pond System Discharge)

During the period beginning on the effective date of this permit and lasting until the expiration date of this permit, the permittee is authorized to discharge a maximum of 7.77 MGD of bottom ash transport water; chemical metal cleaning wastewater; coal pile runoff; low volume wastewater, which includes but is not limited to: boiler blowdown, boiler drainage, recirculating house service water, laboratory and sampling streams, reverse osmosis backwash and reject, and water from floor drains; storm water; leachate retention pond water; and groundwater seepage from ash ponds and recirculation pond from Monitoring Point 001B through Monitoring Point 001A and Outfall 001. Outfall 001 discharges to Lake Michigan at Latitude 42.91164, Longitude -86.21269. Such discharge shall be limited and monitored by the permittee as specified below.

<u>Parameter</u>	<u>Maximum Limits for Quantity or Loading</u>			<u>Maximum Limits for Quality or Concentration</u>			<u>Monitoring Frequency</u>	<u>Sample Type</u>
	<u>Monthly</u>	<u>Daily</u>	<u>Units</u>	<u>Monthly</u>	<u>Daily</u>	<u>Units</u>		
Flow	---	(report)	MGD	---	---	---	Monthly	Report Total Daily Flow
Total Suspended Solids	---	---	---	30	50	mg/l	Monthly	Grab
Oil & Grease	---	---	---	15	20	mg/l	Annually	Grab
Total Copper, see Part I.A.2.a.	---	---	---	---	1.0	mg/l	Daily	Grab
Total Iron, see Part I.A.2.a.	---	---	---	---	1.0	mg/l	Daily	Grab

- a. **Total Copper and Total Iron Limits**
The limits and monitoring requirements for total copper and total iron apply only to the discharge from the chemical treatment facility when operating. The chemical treatment facility effluent shall not be mixed with any other waste stream prior to sampling for compliance monitoring. All samples shall be taken prior to discharge to the recirculation pond.
- b. **Monitoring Location**
Samples, measurements, and observations taken in compliance with the monitoring requirements above shall be taken prior to the Unit 2 condenser discharge channel.
- c. **Annual Monitoring**
Annual samples shall be taken during the month of April. If the facility does not discharge during this month, the permittee shall sample the next discharge occurring during the period in question. If the facility does not discharge during the period in question, a sample is not required for that period. For any month in which a sample is not taken, the permittee shall enter "G" on the Discharge Monitoring Report (DMR).

PART I**Section A. Limitations and Monitoring Requirements**

- d. **Analytical Methods and Quantification Levels for Total Copper**
 The sampling procedures, preservation and handling, and analytical protocol for compliance monitoring for Total Copper shall be in accordance with Part II.B.2. of this permit. The quantification level for Total Copper shall be 1.0 ug/l unless a higher level is appropriate because of sample matrix interference. Justification for higher quantification levels shall be submitted to the Department within 30 days of such determination. Upon approval from the Department, the permittee may use alternate analytical methods (for parameters with methods specified in Title 40 of the Code of Federal Regulations (CFR), Part 136, the alternate methods are restricted to those listed in 40 CFR, Part 136).

3. Effluent Limitations, Monitoring Point 001C (Plant Oil/Water Separator Discharge)

During the period beginning on the effective date of this permit and lasting until the expiration date of this permit, the permittee is authorized to discharge a maximum of 9.65 MGD of noncontact cooling water; low volume wastewater, which includes but is not limited to: boiler blowdown, recirculating house service water, laboratory and sampling streams, and water from floor drains; treated coal pile runoff; and storm water from Monitoring Point 001C through Monitoring Point 001A and Outfall 001. Outfall 001 discharges to Lake Michigan at Latitude 42.91164, Longitude -86.21269. Such discharge shall be limited and monitored by the permittee as specified below.

<u>Parameter</u>	<u>Maximum Limits for Quantity or Loading</u>			<u>Maximum Limits for Quality or Concentration</u>			<u>Monitoring Frequency</u>	<u>Sample Type</u>
	<u>Monthly</u>	<u>Daily</u>	<u>Units</u>	<u>Monthly</u>	<u>Daily</u>	<u>Units</u>		
Flow	---	(report)	MGD	---	---	---	Monthly	Report Total Daily Flow
Total Suspended Solids	---	---	---	25	40	mg/l	Monthly	Grab
Oil & Grease	---	---	---	---	10	mg/l	Monthly	Grab

- a. **Monitoring Location**
 Samples, measurements, and observations taken in compliance with the monitoring requirements above shall be taken prior to discharge to Units 1 & 2 intake channel.
- b. **Monitoring Frequency Reduction for Oil & Grease**
 After the submittal of 12 months of data, the permittee may request, in writing, Department approval for a reduction in monitoring frequency for Oil & Grease. This request shall contain an explanation as to why the reduced monitoring is appropriate. Upon receipt of written approval and consistent with such approval, the permittee may reduce the monitoring frequency indicated in Part I.A.3. of this permit. The monitoring frequency for Oil & Grease shall not be reduced to less than Annually. The Department may revoke the approval for reduced monitoring at any time upon notification to the permittee.

PART I**Section A. Limitations and Monitoring Requirements****4. Effluent Limitations, Monitoring Point 002A (Ash Pond Discharge)**

During the period beginning on the effective date of this permit and lasting until the expiration date of this permit, the permittee is authorized to discharge a maximum of 10.45 MGD of bottom ash transport water; economizer ash wastewater; chemical metal cleaning wastewater; coal pile runoff; low volume wastewater which includes but is not limited to: ion exchange wastewater, boiler blowdown, boiler drainage, recirculating house service water, laboratory and sampling streams, reverse osmosis backwash and reject water, and water from floor drains; storm water; and groundwater seepage from ash ponds and the recirculation pond from Monitoring Point 002A through Outfall 002. Outfall 002 discharges to the Pigeon River at Latitude 42.90292, Longitude -86.196033. Such discharge shall be limited and monitored by the permittee as specified below.

<u>Parameter</u>	<u>Maximum Limits for Quantity or Loading</u>			<u>Maximum Limits for Quality or Concentration</u>			<u>Monitoring Frequency</u>	<u>Sample Type</u>
	<u>Monthly</u>	<u>Daily</u>	<u>Units</u>	<u>Monthly</u>	<u>Daily</u>	<u>Units</u>		
Flow	(report)	(report)	MGD	---	---	---	2X Monthly	Report Total Daily Flow
Total Suspended Solids	---	---	---	30	50	mg/l	Monthly	Grab
Oil & Grease	---	---	---	15	20	mg/l	Annually	Grab
Total Copper, see Part I.A.4.f.	---	---	---	---	(report)	mg/l	Daily	Grab
Total Iron, see Part I.A.4.f.	---	---	---	---	(report)	mg/l	Daily	Grab
Total Arsenic	---	(report)	lbs/day	---	(report)	ug/l	Quarterly	Grab
Total Phosphorus (as P)	---	(report)	lbs/day	---	(report)	mg/l	Quarterly	Grab
Total Selenium	0.47	(report)	lbs/day	5.3	(report)	ug/l	Quarterly	Grab
EVAC (as amine), see Part I.A.4.h.		---	---	---	78	ug/l	See Permit Requirements	Grab
Outfall Observation	(report)	---	---	---	---	---	5X Weekly	Visual
				Minimum Daily				
pH	---	---	---	6.5	9.0	S.U.	2X Monthly	Grab

- a. Narrative Standard
The receiving water shall contain no turbidity, color, oil films, floating solids, foams, settleable solids, or deposits as a result of this discharge in unnatural quantities which are or may become injurious to any designated use.
- b. Monitoring Location
Samples, measurements, and observations taken in compliance with the monitoring requirements above shall be taken prior to discharge to the Pigeon River.
- c. Outfall Observation
Outfall observation shall be reported as "yes" or "no." The permittee shall report yes if this requirement was completed and no if this requirement was not completed. Any unusual characteristics of the discharge (i.e., unnatural turbidity, color, oil film, floating solids, foams, settleable solids, suspended

PART I

Section A. Limitations and Monitoring Requirements

solids, or deposits) shall be reported within 24 hours to the Department followed with a written report within 5 days detailing the findings of the investigation and the steps taken to correct the condition.

- d. **Quarterly and Annual Monitoring**
Quarterly samples shall be taken during the months of January, April, July, and October. Annual samples shall be taken during the month of April. If the facility does not discharge during these months, the permittee shall sample the next discharge occurring during the period in question. If the facility does not discharge during the period in question, a sample is not required for that period. For any month in which a sample is not taken, the permittee shall enter "G" on the Discharge Monitoring Report (DMR).
- e. **Water Treatment Additives**
This permit does not authorize the discharge of water treatment additives without approval. Approval of water treatment additives is authorized under separate correspondence. Water treatment additives include any material that is added to water used at the facility or to a wastewater generated by the facility to condition or treat the water. In the event a permittee proposes to discharge water treatment additives, including an increased discharge concentration of a previously approved water treatment additive, the permittee shall submit a request for approval in accordance with Part I.A.6. of this permit.
- f. **Total Copper and Total Iron Monitoring**
The monitoring requirements for total copper and total iron apply only when a discharge from the chemical treatment facility occurs through Monitoring Point 002A.
- g. **Analytical Methods and Quantification Levels for Total Arsenic, Total Copper, and Total Phosphorus**
The sampling procedures, preservation and handling, and analytical protocol for compliance monitoring for Total Arsenic, Total Copper, and Total Phosphorus shall be in accordance with Part II.B.2. of this permit. The quantification level for Total Arsenic, Total Copper, and Total Phosphorus shall be 1.0 ug/l, 1.0 ug/l, and 10 ug/l, respectively, unless a higher level is appropriate because of sample matrix interference. Justification for higher quantification levels shall be submitted to the Department within 30 days of such determination. Upon approval from the Department, the permittee may use alternate analytical methods (for parameters with methods specified in Title 40 of the Code of Federal Regulations (CFR), Part 136, the alternate methods are restricted to those listed in 40 CFR, Part 136).
- h. **Zebra Mussel Control Requirements**
The discharge of EVAC (as amine) is restricted to no more than six (6) times per year, for no more than five (5) days per discharge event. The permittee shall notify the Department at least one (1) week prior to each discharge. Upon initiation of each EVAC treatment, samples shall be collected at Monitoring Point 002A at least once every three hours for a twelve (12) hour period. Once treatment is complete following the twelve (12) hour period, sampling will occur once daily the following day for five consecutive days to show that the concentration (as an amine) measured at Monitoring Point 002A is below detection (zero).

The sampling procedure, preservation and handling, and analytical protocol for compliance monitoring for EVAC (as amine) shall be in accordance with the Acid Orange Method. The quantification level shall not exceed 50 ug/l for EVAC (as amine), unless higher levels are appropriate because of sample matrix interference. Justification for higher quantification levels shall be submitted to the Department within 30 days of such determination. Other methods may be used upon approval from the Department. The highest value measured during the discharge event shall be reported. If the concentration in all samples is less than the quantification level, report "<" the quantification level used by the analyzing laboratory on the DMR.
- i. **Power Plants – Polychlorinated Biphenyls (PCB) Prohibition**
The permittee shall not discharge any PCBs to the receiving waters of the state of Michigan as a result of plant operations.

PART I**Section A. Limitations and Monitoring Requirements****5. Effluent Limitations, Monitoring Point 002C**

During the period beginning on the effective date of this permit and lasting until the expiration date of this permit, the permittee is authorized to discharge a maximum of 1.092 MGD of chemical metal cleaning wastewater from Monitoring Point 002C through Monitoring Point 002A and Outfall 002. Outfall 002 discharges to the Pigeon River at Latitude 42.90292, Longitude -86.196033. Such discharge shall be limited and monitored by the permittee as specified below.

<u>Parameter</u>	<u>Maximum Limits for Quantity or Loading</u>			<u>Maximum Limits for Quality or Concentration</u>			<u>Monitoring Frequency</u>	<u>Sample Type</u>
	<u>Monthly</u>	<u>Daily</u>	<u>Units</u>	<u>Monthly</u>	<u>Daily</u>	<u>Units</u>		
Flow	---	(report)	MGD	---	---	---	Monthly	Report Total Daily Flow
Total Copper, see Part I.A.5.a.	---	---	---	---	1.0	mg/l	Daily	Grab
Total Iron, see Part I.A.5.a.	---	---	---	---	1.0	mg/l	Daily	Grab

- a. **Total Copper and Total Iron Limits**
The limits and monitoring requirements for total copper and total iron apply only to the discharge from the chemical treatment facility when operating. The chemical treatment facility effluent shall not be mixed with any other waste stream prior to sampling for compliance monitoring. All samples shall be taken prior to discharge to the recirculation pond.
- b. **Monitoring Location**
Samples, measurements, and observations taken in compliance with the monitoring requirements above shall be taken prior to the Unit 2 condenser discharge channel.
- c. **Analytical Methods and Quantification Levels for Total Copper**
The sampling procedures, preservation and handling, and analytical protocol for compliance monitoring for Total Copper shall be in accordance with Part II.B.2. of this permit. The quantification level for Total Copper shall be 1.0 ug/l unless a higher level is appropriate because of sample matrix interference. Justification for higher quantification levels shall be submitted to the Department within 30 days of such determination. Upon approval from the Department, the permittee may use alternate analytical methods (for parameters with methods specified in Title 40 of the Code of Federal Regulations (CFR), Part 136, the alternate methods are restricted to those listed in 40 CFR, Part 136).

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Section A. Limitations and Monitoring Requirements

6. Request for Discharge of Water Treatment Additives

Prior to discharge of any water treatment additive, the permittee shall obtain written approval from the Department. Requests for such approval shall be submitted via the Department's MiWaters system. The MiWaters website is located at <https://miwaters.deq.state.mi.us>. Instructions for submitting such a request may be obtained at <http://www.michigan.gov/deqnpdes> (near the bottom of that page, click on one or both of the links located under the Water Treatment Additives banner). Additional monitoring and reporting may be required as a condition for the approval to discharge the additive.

A request to discharge water treatment additives shall include all of the following usage and discharge information for each water treatment additive proposed to be discharged:

- a. Safety Data Sheet (formerly known as Material Safety Data Sheet);
- b. the proposed water treatment additive discharge concentration with supporting calculations;
- c. the discharge frequency (i.e., number of hours per day and number of days per year);
- d. the outfall and monitoring point from which the product is to be discharged;
- e. the type of removal treatment, if any, that the water treatment additive receives prior to discharge;
- f. the product's function (i.e. microbiocide, flocculant, etc.);
- g. a 48-hour LC₅₀ or EC₅₀ for a North American freshwater planktonic crustacean (either *Ceriodaphnia sp.*, *Daphnia sp.*, or *Simocephalus sp.*); and
- h. the results of a toxicity test for one (1) other North American freshwater aquatic species (other than a planktonic crustacean) that meets a minimum requirement of R 323.1057(2) of the Water Quality Standards. Examples of tests that would meet this requirement include a 96-hour LC₅₀ for rainbow trout, bluegill, or fathead minnow.

7. Cold Shock Prevention

Cessation of thermal inputs to the receiving water by this facility shall occur gradually so as to avoid fish mortality due to cold shock during the winter months (November through March). The basis for this requirement is to allow fish associated with the discharge-heated mixing zone for Outfall 001 to acclimate to the decreasing temperature. The Department acknowledges that the permittee meets this condition based on the equipment and practices implemented at Outfall 001 identified in the application.

8. Intake Screen Backwash, Outfall 001

During the period beginning on the effective date of this permit and lasting until the expiration date of this permit, the permittee is authorized to discharge intake screen backwash from Outfall 001 to Lake Michigan. The permittee shall collect and remove debris accumulated on intake trash bars and dispose of such material on land in an appropriate manner.

9. Periodic/Temporary Rerouting of Combined Plant Discharge

The permittee is authorized to divert the combined flow from Units 1 & 2 and Unit 3 offshore intake structure under the following conditions: (a) for deicing when the intake water temperature falls below 36° F and intakes are at risk of becoming partially or completely restricted because of icing, (b) when Unit 3 is off line during a scheduled or unscheduled outage and the deepwater discharge pumps are turned off, or (c) for thermal treatment or control of zebra mussels and asiatic clams. The permittee is not required to provide any additional monitoring of this discharge because the effluent limitations and monitoring requirements for Outfall 001, for

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Section A. Limitations and Monitoring Requirements

which monitoring/reporting shall be continued as usual during the diversion, will determine compliance with the applicable water quality standards and any other requirements.

10. Cooling Water Intake Structures – Interim Approval

The federal rules promulgated by the United States Environmental Protection Agency (USEPA) in 40 CFR Parts 122 and 125 establishing the requirements of section 316(b) of the Clean Water Act for Existing Facilities took effect October 14, 2014. Beginning October 14, 2014, any facility covered by the rules requesting permit reissuance shall submit an application in accordance with the rules and shall be subject to the best technology available (BTA) standards for impingement mortality and entrainment as defined in the rules. In accordance with 40 CFR 125.95(a)(2), the Department approved the permittee's March 10, 2016, request for an alternate schedule for submission of the information required in 40 CFR 122.21(r). The alternate schedule for submission of the reports identified in the request for is set for April 30, 2018 (received).

The cooling water intake structure operated by the permittee has been evaluated using all available information relating to its location, design, construction, and capacity. At this time, the Department has made an **interim** determination that the cooling water intake structure represents BTA to minimize adverse environmental impact in accordance with section 316(b) of the federal Clean Water Act (33 U.S.C. section 1326). The permittee shall at all times properly operate and maintain the cooling water intake structure and associated equipment to minimize adverse environmental impact. The permittee shall give advance notice to the Department of any planned changes in the location, design, operation, or capacity of the intake structure. If the Department determines that additional technologies or control measures are necessary to reduce the impact of impingement or entrainment, the Department may revise the requirements of this condition. Nothing in this permit shall either be construed to relieve the permittee from civil or criminal penalties for previous or future fish losses, or authorize take for the purposes of a facility's compliance with the Endangered Species Act.

11. Facility Contact

The "Facility Contact" was specified in the application. The permittee may replace the facility contact at any time, and shall notify the Department in writing within 10 days after replacement (including the name, address and telephone number of the new facility contact).

- a. The facility contact shall be (or a duly authorized representative of this person):
 - for a corporation, a principal executive officer of at least the level of vice president; or a designated representative if the representative is responsible for the overall operation of the facility from which the discharge originates, as described in the permit application or other NPDES form,
 - for a partnership, a general partner,
 - for a sole proprietorship, the proprietor, or
 - for a municipal, state, or other public facility, either a principal executive officer, the mayor, village president, city or village manager or other duly authorized employee.
- b. A person is a duly authorized representative only if:
 - the authorization is made in writing to the Department by a person described in paragraph a. of this section; and
 - the authorization specifies either an individual or a position having responsibility for the overall operation of the regulated facility or activity such as the position of plant manager, operator of a well or a well field, superintendent, position of equivalent responsibility, or an individual or position having overall responsibility for environmental matters for the facility (a duly authorized representative may thus be either a named individual or any individual occupying a named position).

Nothing in this section obviates the permittee from properly submitting reports and forms as required by law.

PART I**Section A. Limitations and Monitoring Requirements****12. Discharge Monitoring Report – Quality Assurance Study Program**

The permittee shall participate in the Discharge Monitoring Report – Quality Assurance (DMR-QA) Study Program. The purpose of the DMR-QA Study Program is to annually evaluate the proficiency of all in-house and/or contract laboratory(ies) that perform, on behalf of the facility authorized to discharge under this permit, the analytical testing required under this permit. In accordance with Section 308 of the Clean Water Act (33 U.S.C. § 1318); and R 323.2138 and R 323.2154 of Part 21, Wastewater Discharge Permits, promulgated under Part 31 of the NREPA, participation in the DMR-QA Study Program is required for all major facilities, and for minor facilities selected for participation by the Department.

Annually and in accordance with DMR-QA Study Program requirements and submittal due dates, the permittee shall submit to the Michigan DMR-QA Study Program state coordinator all documentation required by the DMR-QA Study. DMR-QA Study Program participation is required only for the analytes required under this permit and only when those analytes are also identified in the DMR-QA Study.

If the permitted facility's status as a major facility should change, participation in the DMR-QA Study Program may be reevaluated. Questions concerning participation in the DMR-QA Study Program should be directed to the Michigan DMR-QA Study Program state coordinator.

All forms and instructions required for participation in the DMR-QA Study Program, including submittal due dates and state coordinator contact information, can be found at

<http://www.epa.gov/compliance/discharge-monitoring-report-quality-assurance-study-program>.

13. Schedule of Compliance for Bottom Ash Transport Water

The permittee shall manage the discharge of bottom ash transport water (BATW) to surface waters of the state in accordance with EPA's Final Steam Electric Reconsideration Rule (Final Rule), effective October 13, 2020. This schedule of compliance (SOC) is based on two separate compliance pathways established by the Final Rule for BATW: the Cessation of Coal Burning Activities subcategory, and the implementation of an ELG-compliant technology. The permittee shall attain compliance with the Final Rule by completing the following requirements.

a. On or before October 13, 2021, the permittee shall:

1) submit a Notice of Planned Participation (NOPP) in the Cessation of Coal Burning Activities subcategory in accordance with 40 CFR §423.19 – if this compliance pathway is being considered, and/or

2) submit an update on the feasibility evaluation to select an ELG-compliant technology – if this compliance pathway is being considered.

b. On or before April 4, 2022, with the application for reissuance, the permittee shall submit a description of the ELG-compliant technology selected – if the ELG-compliant technology pathway is being considered.

PART I**Section A. Limitations and Monitoring Requirements**

- c. On or before December 31, 2022, the permittee shall:
- 1) submit an annual progress report in accordance with 40 CFR §423.19 to ensure compliance under the Cessation of Coal Burning Activities subcategory – if this compliance pathway is being considered, and/or
 - 2) commence the engineering and design process for implementation of the selected ELG-compliant technology and submit a status report on this process – if this compliance pathway is being considered.
- d. On or before December 31, 2023, the permittee shall submit to the Department a report identifying the final pathway selected for compliance with the Final Rule: either the Cessation of Coal Burning Activities subcategory (including the annual progress report in accordance with 40 CFR §423.19), or the implementation of an ELG-compliant technology.
- e. On or before December 31, 2024, the permittee shall:
- 1) submit an annual progress report in accordance with 40 CFR §423.19 to ensure compliance under the Cessation of Coal Burning Activities subcategory – if this compliance pathway was selected, or
 - 2) continue construction of the selected ELG-compliant technology and submit a construction status report that includes a description of any impediments to final implementation by December 31, 2025 – if this compliance pathway was selected.
- f. On or before December 31, 2025, the permittee shall:
- 1) submit an annual progress report in accordance with 40 CFR §423.19 to ensure compliance under the Cessation of Coal Burning Activities subcategory – if this compliance pathway was selected, or
 - 2) submit an Initial Certification Statement in accordance with 40 CFR §423.19(c) and comply with the requirements set forth in Part I.A.14.b. of this permit – if the ELG-compliant technology pathway was selected.
- g. If the permittee selected the Cessation of Coal Burning Activities subcategory as the final pathway for compliance with the Final Rule, the permittee shall complete the following:
- 1) On or before December 31, 2026, the permittee shall submit an annual progress report in accordance with 40 CFR §423.19 to ensure compliance under the Cessation of Coal Burning Activities subcategory.
 - 2) On or before December 31, 2027, the permittee shall submit an annual progress report in accordance with 40 CFR §423.19 to ensure compliance under the Cessation of Coal Burning Activities subcategory.
 - 3) On or before December 31, 2028, the permittee shall comply with the requirements set forth in Part I.A.14.a. of this permit.

PART I**Section A. Limitations and Monitoring Requirements****14. Bottom Ash Transport Water Discharge Prohibition**

- a. If the permittee has certified to the Department the intention to pursue the Cessation of Coal Burning Activities subcategory as set forth in Part I.A.13. of this permit, then the discharge of all BATW shall comply with the final effluent limitations set forth in Part I.A.2. and Part I.A.4. of this permit until no later than December 31, 2028, by which date the permittee shall cease discharge of newly generated BATW from any outfall and the discharge of previously generated BATW shall comply with the final effluent limitations set forth in Part I.A.2. and Part I.A.4. of this permit.
- b. Beginning December 31, 2025, the permittee is prohibited from discharging newly generated BATW from any outfall in accordance with 40 CFR 423.13(k)(1), except for those discharges to which paragraph (k)(2) applies. After December 31, 2025, any discharge volume of BATW shall be reduced or eliminated to the extent achievable using control measures that are technologically available and economically achievable in light of best industry practices. The total volume of BATW allowed to be discharged under (k)(2) shall be determined by the Department on a case-by-case basis and in no event shall such discharge exceed a 30-day rolling average of 10 percent of the primary active wetted bottom ash system volume. At least 180 days prior to the discharge of any newly generated BATW, the permittee shall submit to the Department all information required under 40 CFR 423.19(c) for reviews required under (k)(2).

The Department may modify or reissue this permit in accordance with applicable rules in order to establish the permit requirements set forth in the rules for 40 CFR Part 423, Steam Electric Power Generating Point Source Category.

PART I**Section B. Storm Water Pollution Prevention****1. Final Effluent Limitations and Monitoring Requirements**

The permittee is authorized to discharge storm water associated with industrial activity, as defined under 40 CFR 122.26(b)(14)(i-ix), to the surface waters of the state. Such discharge shall be limited and monitored by the permittee as specified below.

- a. **Narrative Standard**
The receiving water shall contain no turbidity, color, oil films, floating solids, foams, settleable solids, suspended solids, or deposits as a result of this discharge in unnatural quantities which are or may become injurious to any designated use.
- b. **Visual Assessment of Storm Water Discharges**
To ensure that storm water discharges from the facility do not violate the narrative standard in the receiving waters, storm water discharges shall be visually assessed in accordance with this permit.
- c. **Implementation of Storm Water Pollution Prevention Plan**
The permittee shall implement an acceptable Storm Water Pollution Prevention Plan (SWPPP) as required by this permit.
- d. **Certified Operator**
The permittee shall have an Industrial Storm Water Certified Operator who has supervision over the facility's storm water treatment and control measures included in the SWPPP.

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Section B. Storm Water Pollution Prevention

The Storm Water Pollution Prevention Plan (SWPPP) is a written procedure to reduce the exposure of storm water to significant materials and to reduce the amount of significant materials in the storm water discharge. An acceptable SWPPP shall identify potential sources of contamination and describe the controls necessary to reduce their impacts in accordance with Part I.B.2. through Part I.B.8. of this permit.

2. Source Identification

To identify potential sources of significant materials that can pollute storm water and subsequently be discharged from the facility, the SWPPP shall, at a minimum, include the following:

- a. A site map identifying:
 - 1) buildings and other permanent structures;
 - 2) storage or disposal areas for significant materials;
 - 3) secondary containment structures and descriptions of the significant materials contained within the primary containment structures;
 - 4) storm water discharge points (which include outfalls and points of discharge), numbered or otherwise labeled for reference;
 - 5) location of storm water and non-storm water inlets (numbered or otherwise labeled for reference) contributing to each discharge point;
 - 6) location of NPDES-permitted discharges other than storm water;
 - 7) outlines of the drainage areas contributing to each discharge point;
 - 8) structural controls or storm water treatment facilities;
 - 9) areas of vegetation (with brief descriptions such as lawn, old field, marsh, wooded, etc.);
 - 10) areas of exposed and/or erodible soils and gravel lots;
 - 11) impervious surfaces (e.g., roofs, asphalt, concrete, etc.);
 - 12) name and location of receiving water(s); and
 - 13) areas of known or suspected impacts on surface waters as designated under Part 201 (Environmental Response) of the NREPA.
- b. A list of all significant materials that could pollute storm water. For each material listed, the SWPPP shall include each of the following descriptions:
 - 1) the ways in which each type of significant material has been, or has reasonable potential to become, exposed to storm water (e.g., spillage during handling; leaks from pipes, pumps, and vessels; contact with storage piles, contaminated materials, or soils; waste handling and disposal; deposits from dust or overspray; etc.);

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Section B. Storm Water Pollution Prevention

- 2) identification of the discharge point(s) and the inlet(s) contributing the significant material to each discharge point through which the significant material may be discharged if released; and
- 3) an evaluation of the reasonable potential for contribution of significant materials to storm water from at least the following areas or activities:
 - a) loading, unloading, and other significant material-handling operations;
 - b) outdoor storage, including secondary containment structures;
 - c) outdoor manufacturing or processing activities;
 - d) significant dust- or particulate-generating processes;
 - e) discharge from vents, stacks, and air emission controls;
 - f) on-site waste disposal practices;
 - g) maintenance and cleaning of vehicles, machines, and equipment;
 - h) areas of exposed and/or erodible soils;
 - i) Sites of Environmental Contamination listed under Part 201 (Environmental Response) of the NREPA;
 - j) areas of significant material residues;
 - k) areas where animals (wild or domestic) congregate and deposit wastes; and
 - l) other areas where storm water may come into contact with significant materials.
- c. A listing of significant spills and significant leaks of polluting materials that occurred in areas that are exposed to precipitation or that discharge to a point source at the facility. The listing shall include spills that occurred over the three (3) years prior to the effective date of a permit authorizing discharge. The listing shall include the date, volume, and exact location of the release, and the action taken to clean up the material and/or prevent exposure to storm water or contamination of surface waters of the state. Any release that occurs after the SWPPP has been developed shall be controlled in accordance with the SWPPP and is cause for the SWPPP to be updated as appropriate within 14 calendar days of obtaining knowledge of the spill or loss.
- d. A determination as to whether its facility discharges storm water to a water body for which an EPA-approved Total Maximum Daily Load (TMDL) has been established. If so, the permittee shall assess whether the TMDL requirements for the facility's discharge are being met through the existing SWPPP controls or whether additional control measures are necessary. The permittee's assessment of whether the TMDL requirements are being met shall focus on the effectiveness, adequacy, and implementation of the permittee's SWPPP controls.
- e. A summary of existing storm water discharge sampling data (if available), describing pollutants in storm water discharges at the facility. This summary shall be accompanied by a description of the suspected source(s) of the pollutants detected.

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3. Nonstructural Controls

To prevent significant materials from contacting storm water at the source, the SWPPP shall, at a minimum, include each of the following nonstructural controls:

- a. Written procedures and a schedule for routine preventive maintenance. Preventive maintenance procedures shall describe routine inspections and maintenance of storm water management and control devices (e.g., cleaning of oil/water separators and catch basins, routine housekeeping activities, etc.), as well as inspecting and testing plant equipment and systems to uncover conditions that could cause breakdowns or failures resulting in discharges of pollutants to the storm sewer system or the surface waters of the state. The routine inspection shall include areas of the facility in which significant materials have the reasonable potential to contaminate storm water. A written report of the inspection and corrective actions shall be retained in accordance with Record Keeping, below.
- b. Written procedures and a schedule for good housekeeping to maintain a clean, orderly facility. Good housekeeping procedures shall include routine inspections that focus on the areas of the facility that have a reasonable potential to contaminate storm water entering the property. The routine housekeeping inspections may be combined with the routine inspections for the preventive maintenance program. A written report of the inspection and corrective actions shall be retained in accordance with Record Keeping, below.
- c. Written procedures and a schedule for **quarterly** comprehensive site inspections, to be conducted by the Industrial Storm Water Certified Operator. At a minimum, one inspection shall be performed within each of the following quarters: January-March, April-June, July-September, and October-December. The comprehensive site inspections shall include, but not be limited to, inspection of structural controls in use at the facility, and the areas and equipment identified in the routine preventive maintenance and good housekeeping procedures. These inspections shall also include a review of the routine preventive maintenance reports, good housekeeping inspection reports, and any other paperwork associated with the SWPPP. The permittee may request Department approval of an alternate schedule for comprehensive site inspections. A written report of the inspection and corrective actions shall be retained in accordance with Record Keeping, below, and the following shall be included on the comprehensive inspection form/report:
 - 1) Date of the inspection.
 - 2) Name(s), title(s), and certification number(s) of the personnel conducting the inspection.
 - 3) Precipitation information (i.e., a description of recent rainfall/snowmelt events).
 - 4) All observations relating to the implementation of control measures. Items to include if applicable:
 - a) updates on corrective actions implemented due to previously identified pollutant and/or discharge issues;
 - b) any evidence of, or the potential for, pollutants to discharge to the drainage system or receiving waters and the condition of and around the discharge point including flow dissipation measures needing maintenance or repairs;
 - c) any control measures needing maintenance or repairs; and
 - d) any additional control measures needed to comply with permit requirements.

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- 5) Any required revisions to the SWPPP resulting from the inspection.
- 6) A written certification stating the facility is in compliance with this permit and the SWPPP, or, if there are instances of noncompliance, they are identified.
- 7) Written procedures and a schedule for **quarterly** visual assessments of storm water discharges. At a minimum, one visual assessment shall be conducted within each of the following quarters: January-March, April-June, July-September, and October-December. These assessments shall be conducted as part of the comprehensive site inspection within one month of control measure observations made in accordance with 4), above. If the Department has approved an alternate schedule for the comprehensive site inspection, the visual assessment may likewise be conducted in accordance with the same approved alternate schedule.

The following are the requirements of the visual assessment. The permittee shall develop and clearly document, in writing, procedures for meeting these requirements:

- a) Within six (6) months of the effective date of this permit, the permittee shall develop written procedures for conducting the visual assessment and incorporate these procedures into the SWPPP. If Qualified Personnel rather than an Industrial Storm Water Certified Operator will collect storm water samples, these procedures shall include a written description of the training given to these personnel to qualify them to collect the samples, as well as documentation verifying that these personnel have received this training. The first visual assessment shall be conducted in conjunction with the next occurring comprehensive inspection. If changes resulting in altered drainage patterns occur at the facility, the permittee shall modify the procedures for conducting the visual assessment in accordance with the requirements of Keeping SWPPPs Current, below, and these modifications shall be incorporated into the SWPPP prior to conducting the next visual assessment.
- b) A visual assessment shall be conducted of a representative storm water **sample** collected **from each storm water discharge point**. Storm water samples shall be visually assessed for conditions that could cause a violation of water quality standards as defined in Water Quality Standards, below. The visual assessment shall be made of the storm water sample in a clean, clear glass or plastic container. Only an Industrial Storm Water Certified Operator shall conduct this visual assessment. Visual assessment of the storm water sample shall be conducted within 48 hours of sample collection.

Representative storm water samples shall be collected:

- (1) from each storm water discharge point identified as set forth under Source Identification, above. These samples may be collected by one or more of the following: an Industrial Storm Water Certified Operator; and/or an individual who meets qualifications acceptable to the Department and who is authorized by an Industrial Storm Water Certified Operator to collect the sample ("Qualified Personnel"); and/or an automated sampling device; and
- (2) within the first 30 minutes of the start of a discharge from a storm event and on discharges that occur at least 72 hours (3 days) from the previous discharge. If it is not possible to collect the sample within the first 30 minutes of discharge, the sample shall be collected as soon thereafter as practicable, but not exceeding 60 minutes. In the case of snowmelt, samples shall be collected during a period with measurable discharge from the site.

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- c) A visual assessment shall be conducted of the storm water **discharge at each storm water discharge point**. (If an automated sampling device is used to collect the storm water sample, this requirement is waived). Either an Industrial Storm Water Certified Operator and/or Qualified Personnel may conduct this visual assessment. This visual assessment may be conducted directly – by someone physically present at the storm water discharge at each storm water discharge point; or it may be conducted indirectly – through the use of a visual recording taken of the storm water discharge at each storm water discharge point. Direct visual assessment shall be conducted at the same time that the storm water sample is collected. Indirect visual assessment shall be conducted using a visual recording taken of the storm water discharge at the same time that the storm water sample was collected.
- d) Visual assessments shall be documented. This documentation shall be retained in accordance with Record Keeping, below, and shall include the following:
 - (1) sampling location(s) at the storm water discharge point(s) identified on the site map (see Source Identification, above);
 - (2) storm event information (i.e., length of event expressed in hours, approximate size of event expressed in inches of precipitation, duration of time since previous event that caused a discharge, and date and time the discharge began);
 - (3) date and time of the visual assessment of each storm water **discharge** at each storm water discharge point;
 - (4) name(s) and title(s) of the Industrial Storm Water Certified Operator or Qualified Personnel who conducted the visual assessment of the storm water **discharge** at each storm water discharge point. If an automated sampling device was used to collect the storm water sample associated with this discharge point, this documentation requirement is waived;
 - (5) observations made during visual assessment of the storm water **discharge** at each storm water discharge point. If an automated sampling device was used to collect the storm water sample associated with this discharge point, this documentation requirement is waived;
 - (6) if applicable, any visual recordings used to conduct the visual assessment of the storm water **discharge** at each storm water discharge point;
 - (7) date and time of sample collection for each storm water **sample**;
 - (8) name(s) and title(s) of the Industrial Storm Water Certified Operator or Qualified Personnel who collected the storm water **sample**. If an automated sampling device was used to collect the storm water sample, the permittee shall document that, instead;
 - (9) date and time of the visual assessment of each storm water **sample**;
 - (10) name(s), title(s), and operator number(s) of the Industrial Storm Water Certified Operator(s) who conducted the visual assessment of each storm water **sample**;
 - (11) observations made during visual assessment of each storm water **sample**;

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- (12) full-color photographic evidence of the storm water **sample** against a white background;
 - (13) nature of the discharge (i.e., rainfall or snowmelt);
 - (14) probable sources of any observed storm water contamination; and
 - (15) if applicable, an explanation for why it was not possible to collect samples within the first 30 minutes of discharge.
 - e) When adverse weather conditions prevent a visual assessment during the quarter, a substitute visual assessment shall be conducted during the next qualifying storm event. Documentation of the rationale for no visual assessment during a quarter shall be included with the SWPPP records as described in Record Keeping, below. Adverse conditions are those that are dangerous or create inaccessibility for personnel, such as local flooding, high winds, electrical storms, or situations that otherwise make sampling impractical such as drought or extended frozen conditions.
 - f) If the facility has two (2) or more discharge points that are believed to discharge substantially identical storm water effluents, the facility may conduct visual assessments of the discharge at just one (1) of the discharge points and report that the results also apply to the other substantially identical discharge point(s). The determination of substantially identical discharge points is to be based on the significant material evaluation conducted as set forth under Source Identification, above, and shall be clearly documented in the SWPPP. Visual assessments shall be conducted on a rotating basis of each substantially identical discharge point throughout the period of coverage under this permit.
- d. A description of material handling procedures and storage requirements for significant materials. Equipment and procedures for cleaning up spills shall be identified in the SWPPP and made available to the appropriate personnel. The procedures shall identify measures to prevent spilled materials or material residues from contaminating storm water entering the property. The SWPPP shall include language describing what a reportable spill or release is and the appropriate reporting requirements in accordance with Part II.C.6. and Part II.C.7. The SWPPP may include, by reference, requirements of either a Pollution Incident Prevention Plan (PIPP) prepared in accordance with the Part 5 Rules (R 324.2001 through R 324.2009 of the Michigan Administrative Code); a Hazardous Waste Contingency Plan prepared in accordance with 40 CFR 264 and 265 Subpart D, as required by Part 111 of the NREPA; or a Spill Prevention Control and Countermeasure (SPCC) plan prepared in accordance with 40 CFR 112.
- e. Identification of areas which, due to topography, activities, or other factors, have a high potential for significant soil erosion. Gravel lots shall be included. The SWPPP shall also identify measures used to control soil erosion and sedimentation.
- f. A description of the employee training program that will be implemented on an annual basis to inform appropriate personnel at all levels of their responsibility as it relates to the components and goals of the SWPPP. The SWPPP shall identify periodic dates for the employee training program. Records of the employee training program shall be retained in accordance with Record Keeping, below.
- g. Identification of actions to limit the discharge of significant materials in order to comply with TMDL requirements, if applicable.

PART I

Section B. Storm Water Pollution Prevention

- h. Identification of significant materials expected to be present in storm water discharges following implementation of nonstructural preventive measures and source controls.

4. Structural Controls

Where implementation of the measures required by Nonstructural Controls, above, does not control storm water discharges in accordance with Water Quality Standards, below, the SWPPP shall provide a description of the location, function, design criteria, and installation/construction schedule of structural controls for prevention and treatment. Structural controls may be necessary:

- a. to prevent uncontaminated storm water from contacting, or being contacted by, significant materials; or
- b. if preventive measures are not feasible or are inadequate to keep significant materials at the site from contaminating storm water. Structural controls shall be used to treat, divert, isolate, recycle, reuse, or otherwise manage storm water in a manner that reduces the level of significant materials in the storm water and provides compliance with water quality standards as identified in Water Quality Standards, below.

5. Keeping SWPPPs Current

- a. The permittee and/or the Industrial Storm Water Certified Operator shall review the SWPPP annually after it is developed and maintain a written report of the review in accordance with Record Keeping, below. Based on the review, the permittee or the Industrial Storm Water Certified Operator shall amend the SWPPP as needed to ensure continued compliance with the terms and conditions of this permit. The written report shall be submitted to the Department on or before January 10th of each year.
- b. The SWPPP developed under the conditions of a previous permit shall be amended as necessary to ensure compliance with this permit.
- c. The SWPPP shall be updated or amended whenever changes at the facility have the potential to increase the exposure of significant materials to storm water, significant spills occur at the facility, or when the SWPPP is determined by the permittee or the Department to be ineffective in achieving the general objectives of controlling pollutants in storm water discharges associated with industrial activity. Updates based on increased activity or spills at the facility shall include a description of how the permittee intends to control any new sources of significant materials, or respond to and prevent spills in accordance with the requirements of this permit (see Source Identification; Nonstructural Controls; and Structural Controls, above).
- d. The Department may notify the permittee at any time that the SWPPP does not meet minimum requirements of this permit. Such notification shall identify why the SWPPP does not meet minimum requirements of this permit. The permittee shall make the required changes to the SWPPP within 30 days after such notification from the Department or authorized representative and shall submit to the Department a written certification that the requested changes have been made.
- e. Amendments to the SWPPP shall be signed and retained on-site with the SWPPP pursuant to Signature and SWPPP Review, below.

PART I**Section B. Storm Water Pollution Prevention****6. Industrial Storm Water Certified Operator Update**

If the Industrial Storm Water Certified Operator is changed or an Industrial Storm Water Certified Operator is added, the permittee shall provide the name and certification number of the new Industrial Storm Water Certified Operator to the Department. If a facility has multiple Industrial Storm Water Certified Operators, the names and certification numbers of all shall be included in the SWPPP.

7. Signature and SWPPP Review

- a. The SWPPP shall be reviewed and signed by the Industrial Storm Water Certified Operator(s) and by either the permittee or an authorized representative in accordance with 40 CFR 122.22. The SWPPP and associated records shall be retained on-site at the facility that generates the storm water discharge.
- b. The permittee shall make the SWPPP, reports, log books, storm water discharge sampling data (if collected), and items required by Record Keeping, below, available upon request to the Department. The Department makes the non-confidential business portions of the SWPPP available to the public.

8. Record Keeping

The permittee shall maintain records of all SWPPP-related inspection and maintenance activities. Records shall also be kept describing incidents such as spills or other discharges that can affect the quality of storm water. All such records shall be retained for three (3) years. The following records are required by this permit (see Nonstructural Controls; and Keeping SWPPPs Current, above):

- a. routine preventive maintenance inspection reports;
- b. routine good housekeeping inspection reports;
- c. comprehensive site inspection reports;
- d. documentation of visual assessments;
- e. employee training records; and
- f. written summaries of the annual SWPPP review.

PART I**Section B. Storm Water Pollution Prevention****9. Water Quality Standards**

At the time of discharge, there shall be no violation of water quality standards in the receiving waters as a result of the storm water discharge. This requirement includes, but is not limited to, the following conditions:

- a. In accordance with R 323.1050 of the Part 4 Rules promulgated pursuant to Part 31 of the NREPA, the receiving waters shall not have any of the following unnatural physical properties as a result of this discharge in quantities which are, or may become, injurious to any designated use: turbidity, color, oil films, floating solids, foams, settleable solids, suspended solids, or deposits.
- b. Any unusual characteristics of the discharge (i.e., unnatural turbidity, color, oil film, floating solids, foams, settleable solids, suspended solids, or deposits) shall be reported within 24 hours to the Department, followed by a written report within five (5) days detailing the findings of the investigation and the steps taken to correct the condition.
- c. Any pollutant for which a level of control is specified to meet a TMDL established by the Department shall be controlled at the facility so that its discharge is reduced by/to the amount specified in the TMDL.

PART I**Section B. Storm Water Pollution Prevention****10. Prohibition of Non-Storm Water Discharges**

Discharges of material other than storm water shall be in compliance with an NPDES permit issued for the discharge. Storm water shall be defined to include all of the following non-storm water discharges, provided pollution prevention controls for the non-storm water component are identified in the SWPPP:

- a. discharges from fire hydrant flushing;
- b. potable water sources, including water line flushing;
- c. water from fire system testing and fire-fighting training without burned materials or chemical fire suppressants;
- d. irrigation drainage;
- e. lawn watering;
- f. routine building wash-down that does not use detergents or other compounds;
- g. pavement wash waters where contamination by toxic or hazardous materials has not occurred (unless all contamination by toxic or hazardous materials has been removed) and where detergents are not used;
- h. uncontaminated condensate from air conditioners, coolers, and other compressors and from the outside storage of refrigerated gases or liquids;
- i. springs;
- j. uncontaminated groundwater;
- k. foundation or footing drains where flows are not contaminated with process materials such as solvents; and
- l. discharges from fire-fighting activities. Discharges from fire-fighting activities are exempted from the requirement to be identified in the SWPPP.

11. Tracer Dye Discharges

This permit does not authorize the discharge of tracer dyes without approval from the Department. Requests to discharge tracer dyes shall be submitted to the Department in accordance with Rule 1097 (R 323.1097 of the Michigan Administrative Code).

PART II

Part II may include terms and /or conditions not applicable to discharges covered under this permit.

Section A. Definitions

Acute toxic unit (TU_A) means $100/LC_{50}$ where the LC_{50} is determined from a whole effluent toxicity (WET) test which produces a result that is statistically or graphically estimated to be lethal to 50% of the test organisms.

Annual monitoring frequency refers to a calendar year beginning on January 1 and ending on December 31. When required by this permit, an analytical result, reading, value or observation shall be reported for that period if a discharge occurs during that period.

Authorized public agency means a state, local, or county agency that is designated pursuant to the provisions of section 9110 of Part 91 of the NREPA to implement soil erosion and sedimentation control requirements with regard to construction activities undertaken by that agency.

Best management practices (BMPs) means structural devices or nonstructural practices that are designed to prevent pollutants from entering into storm water, to direct the flow of storm water, or to treat polluted storm water.

Bioaccumulative chemical of concern (BCC) means a chemical which, upon entering the surface waters, by itself or as its toxic transformation product, accumulates in aquatic organisms by a human health bioaccumulation factor of more than 1000 after considering metabolism and other physiochemical properties that might enhance or inhibit bioaccumulation. The human health bioaccumulation factor shall be derived according to R 323.1057(5). Chemicals with half-lives of less than 8 weeks in the water column, sediment, and biota are not BCCs. The minimum bioaccumulation concentration factor (BAF) information needed to define an organic chemical as a BCC is either a field-measured BAF or a BAF derived using the biota-sediment accumulation factor (BSAF) methodology. The minimum BAF information needed to define an inorganic chemical as a BCC, including an organometal, is either a field-measured BAF or a laboratory-measured bioconcentration factor (BCF). The BCCs to which these rules apply are identified in Table 5 of R 323.1057 of the Water Quality Standards.

Biosolids are the solid, semisolid, or liquid residues generated during the treatment of sanitary sewage or domestic sewage in a treatment works. This includes, but is not limited to, scum or solids removed in primary, secondary, or advanced wastewater treatment processes and a derivative of the removed scum or solids.

Bulk biosolids means biosolids that are not sold or given away in a bag or other container for application to a lawn or home garden.

Certificate of Coverage (COC) is a document, issued by the Department, which authorizes a discharge under a general permit.

Chronic toxic unit (TU_C) means $100/MATC$ or $100/IC_{25}$, where the maximum acceptable toxicant concentration (MATC) and IC_{25} are expressed as a percent effluent in the test medium.

Class B biosolids refers to material that has met the Class B pathogen reduction requirements or equivalent treatment by a Process to Significantly Reduce Pathogens (PSRP) in accordance with the Part 24 Rules. Processes include aerobic digestion, composting, anaerobic digestion, lime stabilization and air drying.

Combined sewer system is a sewer system in which storm water runoff is combined with sanitary wastes.

PART II

Section A. Definitions

Daily concentration is the sum of the concentrations of the individual samples of a parameter divided by the number of samples taken during any calendar day. If the parameter concentration in any sample is less than the quantification limit, regard that value as zero when calculating the daily concentration. The daily concentration will be used to determine compliance with any maximum and minimum daily concentration limitations (except for pH and dissolved oxygen). When required by the permit, report the maximum calculated daily concentration for the month in the "MAXIMUM" column under "QUALITY OR CONCENTRATION" on the Discharge Monitoring Reports (DMRs).

For pH, report the maximum value of any *individual* sample taken during the month in the "MAXIMUM" column under "QUALITY OR CONCENTRATION" on the DMRs and the minimum value of any *individual* sample taken during the month in the "MINIMUM" column under "QUALITY OR CONCENTRATION" on the DMRs. For dissolved oxygen, report the minimum concentration of any *individual* sample in the "MINIMUM" column under "QUALITY OR CONCENTRATION" on the DMRs.

Daily loading is the total discharge by weight of a parameter discharged during any calendar day. This value is calculated by multiplying the daily concentration by the total daily flow and by the appropriate conversion factor. The daily loading will be used to determine compliance with any maximum daily loading limitations. When required by the permit, report the maximum calculated daily loading for the month in the "MAXIMUM" column under "QUANTITY OR LOADING" on the DMRs.

Daily monitoring frequency refers to a 24-hour day. When required by this permit, an analytical result, reading, value or observation shall be reported for that period if a discharge occurs during that period.

Department means the Michigan Department of Environment, Great Lakes, and Energy.

Detection level means the lowest concentration or amount of the target analyte that can be determined to be different from zero by a single measurement at a stated level of probability.

Discharge means the addition of any waste, waste effluent, wastewater, pollutant, or any combination thereof to any surface water of the state.

EC₅₀ means a statistically or graphically estimated concentration that is expected to cause 1 or more specified effects in 50% of a group of organisms under specified conditions.

Fecal coliform bacteria monthly

FOR WWSLs THAT COLLECT AND STORE WASTEWATER AND ARE AUTHORIZED TO DISCHARGE ONLY IN THE SPRING AND/OR FALL ON AN INTERMITTENT BASIS – Fecal coliform bacteria monthly is the geometric mean of all daily concentrations determined during a discharge event. Days on which no daily concentration is determined shall not be used to determine the calculated monthly value. The calculated monthly value will be used to determine compliance with the maximum monthly fecal coliform bacteria limitations. When required by the permit, report the calculated monthly value in the "AVERAGE" column under "QUALITY OR CONCENTRATION" on the DMR. If the period in which the discharge event occurred was partially in each of two months, the calculated monthly value shall be reported on the DMR of the month in which the last day of discharge occurred.

FOR ALL OTHER DISCHARGES – Fecal coliform bacteria monthly is the geometric mean of all daily concentrations determined during a reporting month. Days on which no daily concentration is determined shall not be used to determine the calculated monthly value. The calculated monthly value will be used to determine compliance with the maximum monthly fecal coliform bacteria limitations. When required by the permit, report the calculated monthly value in the "AVERAGE" column under "QUALITY OR CONCENTRATION" on the DMR.

PART II

Section A. Definitions

Fecal coliform bacteria 7-day

FOR WWSLs THAT COLLECT AND STORE WASTEWATER AND ARE AUTHORIZED TO DISCHARGE ONLY IN THE SPRING AND/OR FALL ON AN INTERMITTENT BASIS – Fecal coliform bacteria 7-day is the geometric mean of the daily concentrations determined during any 7 consecutive days of discharge during a discharge event. If the number of daily concentrations determined during the discharge event is less than 7 days, the number of actual daily concentrations determined shall be used for the calculation. Days on which no daily concentration is determined shall not be used to determine the value. The calculated 7-day value will be used to determine compliance with the maximum 7-day fecal coliform bacteria limitations. When required by the permit, report the maximum calculated 7-day geometric mean value for the month in the “MAXIMUM” column under “QUALITY OR CONCENTRATION” on the DMRs. If the 7-day period was partially in each of two months, the value shall be reported on the DMR of the month in which the last day of discharge occurred.

FOR ALL OTHER DISCHARGES – Fecal coliform bacteria 7-day is the geometric mean of the daily concentrations determined during any 7 consecutive days in a reporting month. If the number of daily concentrations determined is less than 7, the actual number of daily concentrations determined shall be used for the calculation. Days on which no daily concentration is determined shall not be used to determine the value. The calculated 7-day value will be used to determine compliance with the maximum 7-day fecal coliform bacteria limitations. When required by the permit, report the maximum calculated 7-day geometric mean for the month in the “MAXIMUM” column under “QUALITY OR CONCENTRATION” on the DMRs. The first calculation shall be made on day 7 of the reporting month, and the last calculation shall be made on the last day of the reporting month.

Flow-proportioned sample is a composite sample with the sample volume proportional to the effluent flow.

General permit means a National Pollutant Discharge Elimination System permit issued authorizing a category of similar discharges.

Geometric mean is the average of the logarithmic values of a base 10 data set, converted back to a base 10 number.

Grab sample is a single sample taken at neither a set time nor flow.

IC₂₅ means the toxicant concentration that would cause a 25% reduction in a nonquantal biological measurement for the test population.

Illicit connection means a physical connection to a municipal separate storm sewer system that primarily conveys non-storm water discharges other than uncontaminated groundwater into the storm sewer; or a physical connection not authorized or permitted by the local authority, where a local authority requires authorization or a permit for physical connections.

Illicit discharge means any discharge to, or seepage into, a municipal separate storm sewer system that is not composed entirely of storm water or uncontaminated groundwater. Illicit discharges include non-storm water discharges through pipes or other physical connections; dumping of motor vehicle fluids, household hazardous wastes, domestic animal wastes, or litter; collection and intentional dumping of grass clippings or leaf litter; or unauthorized discharges of sewage, industrial waste, restaurant wastes, or any other non-storm water waste directly into a separate storm sewer.

Individual permit means a site-specific NPDES permit.

Inlet means a catch basin, roof drain, conduit, drain tile, retention pond riser pipe, sump pump, or other point where storm water or wastewater enters into a closed conveyance system prior to discharge off site or into waters of the state.

PART II

Section A. Definitions

Interference is a discharge which, alone or in conjunction with a discharge or discharges from other sources, both: 1) inhibits or disrupts the POTW, its treatment processes or operations, or its sludge processes, use or disposal; and 2) therefore, is a cause of a violation of any requirement of the POTW's NPDES permit (including an increase in the magnitude or duration of a violation) or, of the prevention of sewage sludge use or disposal in compliance with the following statutory provisions and regulations or permits issued thereunder (or more stringent state or local regulations): Section 405 of the Clean Water Act, the Solid Waste Disposal Act (SWDA) (including Title II, more commonly referred to as the Resource Conservation and Recovery Act (RCRA), and including state regulations contained in any state sludge management plan prepared pursuant to Subtitle D of the SWDA), the Clean Air Act, the Toxic Substances Control Act, and the Marine Protection, Research and Sanctuaries Act. [This definition does not apply to sample matrix interference].

Land application means spraying or spreading biosolids or a biosolids derivative onto the land surface, injecting below the land surface, or incorporating into the soil so that the biosolids or biosolids derivative can either condition the soil or fertilize crops or vegetation grown in the soil.

LC₅₀ means a statistically or graphically estimated concentration that is expected to be lethal to 50% of a group of organisms under specified conditions.

Maximum acceptable toxicant concentration (MATC) means the concentration obtained by calculating the geometric mean of the lower and upper chronic limits from a chronic test. A lower chronic limit is the highest tested concentration that did not cause the occurrence of a specific adverse effect. An upper chronic limit is the lowest tested concentration which did cause the occurrence of a specific adverse effect and above which all tested concentrations caused such an occurrence.

Maximum extent practicable means implementation of best management practices by a public body to comply with an approved storm water management program as required by a national permit for a municipal separate storm sewer system, in a manner that is environmentally beneficial, technically feasible, and within the public body's legal authority.

MGD means million gallons per day.

Monthly concentration is the sum of the daily concentrations determined during a reporting period divided by the number of daily concentrations determined. The calculated monthly concentration will be used to determine compliance with any maximum monthly concentration limitations. Days with no discharge shall not be used to determine the value. When required by the permit, report the calculated monthly concentration in the "AVERAGE" column under "QUALITY OR CONCENTRATION" on the DMR.

For minimum percent removal requirements, the monthly influent concentration and the monthly effluent concentration shall be determined. The calculated monthly percent removal, which is equal to 100 times the quantity [1 minus the quantity (monthly effluent concentration divided by the monthly influent concentration)], shall be reported in the "MINIMUM" column under "QUALITY OR CONCENTRATION" on the DMRs.

Monthly loading is the sum of the daily loadings of a parameter divided by the number of daily loadings determined during a reporting period. The calculated monthly loading will be used to determine compliance with any maximum monthly loading limitations. Days with no discharge shall not be used to determine the value. When required by the permit, report the calculated monthly loading in the "AVERAGE" column under "QUANTITY OR LOADING" on the DMR.

Monthly monitoring frequency refers to a calendar month. When required by this permit, an analytical result, reading, value or observation shall be reported for that period if a discharge occurs during that period.

PART II

Section A. Definitions

Municipal separate storm sewer means a conveyance or system of conveyances designed or used for collecting or conveying storm water which is not a combined sewer and which is not part of a publicly-owned treatment works as defined in the Code of Federal Regulations at 40 CFR 122.2.

Municipal separate storm sewer system (MS4) means all separate storm sewers that are owned or operated by the United States, a state, city, village, township, county, district, association, or other public body created by or pursuant to state law, having jurisdiction over disposal of sewage, industrial wastes, storm water, or other wastes, including special districts under state law, such as a sewer district, flood control district, or drainage district, or similar entity, or a designated or approved management agency under Section 208 of the Federal Act that discharges to the waters of the state. This term includes systems similar to separate storm sewer systems in municipalities, such as systems at military bases, large hospital or prison complexes, and highways and other thoroughfares. The term does not include separate storm sewers in very discrete areas, such as individual buildings.

National Pretreatment Standards are the regulations promulgated by or to be promulgated by the Federal Environmental Protection Agency pursuant to Section 307(b) and (c) of the Federal Act. The standards establish nationwide limits for specific industrial categories for discharge to a POTW.

No observed adverse effect level (NOAEL) means the highest tested dose or concentration of a substance which results in no observed adverse effect in exposed test organisms where higher doses or concentrations result in an adverse effect.

Noncontact cooling water is water used for cooling which does not come into direct contact with any raw material, intermediate product, by-product, waste product or finished product.

Nondomestic user is any discharger to a POTW that discharges wastes other than or in addition to water-carried wastes from toilet, kitchen, laundry, bathing or other facilities used for household purposes.

Outfall is the location at which a point source discharge enters the surface waters of the state.

Part 91 agency means an agency that is designated by a county board of commissioners pursuant to the provisions of section 9105 of Part 91 of the NREPA; an agency that is designated by a city, village, or township in accordance with the provisions of section 9106 of Part 91 of the NREPA; or the Department for soil erosion and sedimentation activities under Part 615, Part 631, or Part 632 pursuant to the provisions of section 9115 of Part 91 of the NREPA.

Part 91 permit means a soil erosion and sedimentation control permit issued by a Part 91 agency pursuant to the provisions of Part 91 of the NREPA.

Partially treated sewage is any sewage, sewage and storm water, or sewage and wastewater, from domestic or industrial sources that is treated to a level less than that required by the permittee's National Pollutant Discharge Elimination System permit, or that is not treated to national secondary treatment standards for wastewater, including discharges to surface waters from retention treatment facilities.

Point of discharge is the location of a point source discharge where storm water is discharged directly into a separate storm sewer system.

Point source discharge means a discharge from any discernible, confined, discrete conveyance, including but not limited to any pipe, ditch, channel, tunnel, conduit, well, discrete fissure, container, or rolling stock. Changing the surface of land or establishing grading patterns on land will result in a point source discharge where the runoff from the site is ultimately discharged to waters of the state.

Polluting material means any material, in solid or liquid form, identified as a polluting material under the Part 5 Rules (R 324.2001 through R 324.2009 of the Michigan Administrative Code).

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Section A. Definitions

POTW is a publicly owned treatment work.

Pretreatment is reducing the amount of pollutants, eliminating pollutants, or altering the nature of pollutant properties to a less harmful state prior to discharge into a public sewer. The reduction or alteration can be by physical, chemical, or biological processes, process changes, or by other means. Dilution is not considered pretreatment unless expressly authorized by an applicable National Pretreatment Standard for a particular industrial category.

Public (as used in the MS4 individual permit) means all persons who potentially could affect the authorized storm water discharges, including, but not limited to, residents, visitors to the area, public employees, businesses, industries, and construction contractors and developers.

Public body means the United States; the state of Michigan; a city, village, township, county, school district, public college or university, or single-purpose governmental agency; or any other body which is created by federal or state statute or law.

Qualified Personnel means an individual who meets qualifications acceptable to the Department and who is authorized by an Industrial Storm Water Certified Operator to collect the storm water sample.

Qualifying storm event means a storm event causing greater than 0.1 inch of rainfall and occurring at least 72 hours after the previous measurable storm event that also caused greater than 0.1 inch of rainfall. Upon request, the Department may approve an alternate definition meeting the condition of a qualifying storm event.

Quantification level means the measurement of the concentration of a contaminant obtained by using a specified laboratory procedure calculated at a specified concentration above the detection level. It is considered the lowest concentration at which a particular contaminant can be quantitatively measured using a specified laboratory procedure for monitoring of the contaminant.

Quarterly monitoring frequency refers to a three month period, defined as January through March, April through June, July through September, and October through December. When required by this permit, an analytical result, reading, value or observation shall be reported for that period if a discharge occurs during that period.

Regional Administrator is the Region 5 Administrator, U.S. EPA, located at R-19J, 77 W. Jackson Blvd., Chicago, Illinois 60604.

Regulated area means the permittee's urbanized area, where urbanized area is defined as a place and its adjacent densely-populated territory that together have a minimum population of 50,000 people as defined by the United States Bureau of the Census and as determined by the latest available decennial census.

Secondary containment structure means a unit, other than the primary container, in which significant materials are packaged or held, which is required by State or Federal law to prevent the escape of significant materials by gravity into sewers, drains, or otherwise directly or indirectly into any sewer system or to the surface or ground waters of this state.

Separate storm sewer system means a system of drainage, including, but not limited to, roads, catch basins, curbs, gutters, parking lots, ditches, conduits, pumping devices, or man-made channels, which is not a combined sewer where storm water mixes with sanitary wastes, and is not part of a POTW.

Significant industrial user is a nondomestic user that: 1) is subject to Categorical Pretreatment Standards under 40 CFR 403.6 and 40 CFR Chapter I, Subchapter N; or 2) discharges an average of 25,000 gallons per day or more of process wastewater to a POTW (excluding sanitary, noncontact cooling and boiler blowdown wastewater); contributes a process waste stream which makes up five (5) percent or more of the average dry weather hydraulic or organic capacity of the POTW treatment plant; or is designated as such by the permittee as defined in 40 CFR 403.12(a) on the basis that the industrial user has a reasonable potential for adversely

PART II

Section A. Definitions

affecting the POTW's treatment plant operation or violating any pretreatment standard or requirement (in accordance with 40 CFR 403.8(f)(6)).

Significant materials Significant Materials means any material which could degrade or impair water quality, including but not limited to: raw materials; fuels; solvents, detergents, and plastic pellets; finished materials such as metallic products; hazardous substances designated under Section 101(14) of Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) (see 40 CFR 372.65); any chemical the facility is required to report pursuant to Section 313 of Emergency Planning and Community Right-to-Know Act (EPCRA); polluting materials as identified under the Part 5 Rules (R 324.2001 through R 324.2009 of the Michigan Administrative Code); Hazardous Wastes as defined in Part 111 of the NREPA; fertilizers; pesticides; and waste products such as ashes, slag, and sludge that have the potential to be released with storm water discharges.

Significant spills and significant leaks means any release of a polluting material reportable under the Part 5 Rules (R 324.2001 through R 324.2009 of the Michigan Administrative Code).

Special-use area means secondary containment structures required by state or federal law; lands on Michigan's List of Sites of Environmental Contamination pursuant to Part 201, Environmental Remediation, of the NREPA; and/or areas with other activities that may contribute pollutants to the storm water for which the Department determines monitoring is needed.

Stoichiometric means the quantity of a reagent calculated to be necessary and sufficient for a given chemical reaction.

Storm water means storm water runoff, snow melt runoff, surface runoff and drainage, and non-storm water included under the conditions of this permit.

Storm water discharge point is the location where the point source discharge of storm water is directed to surface waters of the state or to a separate storm sewer. It includes the location of all point source discharges where storm water exits the facility, including *outfalls* which discharge directly to surface waters of the state, and *points of discharge* which discharge directly into separate storm sewer systems.

SWPPP means the Storm Water Pollution Prevention Plan prepared in accordance with this permit.

Tier I value means a value for aquatic life, human health or wildlife calculated under R 323.1057 of the Water Quality Standards using a tier I toxicity database.

Tier II value means a value for aquatic life, human health or wildlife calculated under R 323.1057 of the Water Quality Standards using a tier II toxicity database.

Total maximum daily loads (TMDLs) are required by the Federal Act for waterbodies that do not meet water quality standards. TMDLs represent the maximum daily load of a pollutant that a waterbody can assimilate and meet water quality standards, and an allocation of that load among point sources, nonpoint sources, and a margin of safety.

Toxicity reduction evaluation (TRE) means a site-specific study conducted in a stepwise process designed to identify the causative agents of effluent toxicity, isolate the sources of toxicity, evaluate the effectiveness of toxicity control options, and then confirm the reduction in effluent toxicity.

Water Quality Standards means the Part 4 Water Quality Standards promulgated pursuant to Part 31 of the NREPA, being R 323.1041 through R 323.1117 of the Michigan Administrative Code.

PART II

Section A. Definitions

Weekly monitoring frequency refers to a calendar week which begins on Sunday and ends on Saturday. When required by this permit, an analytical result, reading, value or observation shall be reported for that period if a discharge occurs during that period.

WWSL is a wastewater stabilization lagoon.

WWSL discharge event is a discrete occurrence during which effluent is discharged to the surface water up to 10 days of a consecutive 14 day period.

3-portion composite sample is a sample consisting of three equal-volume grab samples collected at equal intervals over an 8-hour period.

7-day concentration

FOR WWSLs THAT COLLECT AND STORE WASTEWATER AND ARE AUTHORIZED TO DISCHARGE ONLY IN THE SPRING AND/OR FALL ON AN INTERMITTENT BASIS – The 7-day concentration is the sum of the daily concentrations determined during any 7 consecutive days of discharge during a WWSL discharge event divided by the number of daily concentrations determined. If the number of daily concentrations determined during the WWSL discharge event is less than 7 days, the number of actual daily concentrations determined shall be used for the calculation. The calculated 7-day concentration will be used to determine compliance with any maximum 7-day concentration limitations. When required by the permit, report the maximum calculated 7-day concentration for the WWSL discharge event in the “MAXIMUM” column under “QUALITY OR CONCENTRATION” on the DMR. If the WWSL discharge event was partially in each of two months, the value shall be reported on the DMR of the month in which the last day of discharge occurred.

FOR ALL OTHER DISCHARGES – The 7-day concentration is the sum of the daily concentrations determined during any 7 consecutive days in a reporting month divided by the number of daily concentrations determined. If the number of daily concentrations determined is less than 7, the actual number of daily concentrations determined shall be used for the calculation. The calculated 7-day concentration will be used to determine compliance with any maximum 7-day concentration limitations in the reporting month. When required by the permit, report the maximum calculated 7-day concentration for the month in the “MAXIMUM” column under “QUALITY OR CONCENTRATION” on the DMR. The first 7-day calculation shall be made on day 7 of the reporting month, and the last calculation shall be made on the last day of the reporting month.

PART II

Section A. Definitions

7-day loading

FOR WWSLs THAT COLLECT AND STORE WASTEWATER AND ARE AUTHORIZED TO DISCHARGE ONLY IN THE SPRING AND/OR FALL ON AN INTERMITTENT BASIS – The 7-day loading is the sum of the daily loadings determined during any 7 consecutive days of discharge during a WWSL discharge event divided by the number of daily loadings determined. If the number of daily loadings determined during the WWSL discharge event is less than 7 days, the number of actual daily loadings determined shall be used for the calculation. The calculated 7-day loading will be used to determine compliance with any maximum 7-day loading limitations. When required by the permit, report the maximum calculated 7-day loading for the WWSL discharge event in the “MAXIMUM” column under “QUANTITY OR LOADING” on the DMR. If the WWSL discharge event was partially in each of two months, the value shall be reported on the DMR of the month in which the last day of discharge occurred

FOR ALL OTHER DISCHARGES – The 7-day loading is the sum of the daily loadings determined during any 7 consecutive days in a reporting month divided by the number of daily loadings determined. If the number of daily loadings determined is less than 7, the actual number of daily loadings determined shall be used for the calculation. The calculated 7-day loading will be used to determine compliance with any maximum 7-day loading limitations in the reporting month. When required by the permit, report the maximum calculated 7-day loading for the month in the “MAXIMUM” column under “QUANTITY OR LOADING” on the DMR. The first 7-day calculation shall be made on day 7 of the reporting month, and the last calculation shall be made on the last day of the reporting month.

24-hour composite sample is a flow-proportioned composite sample consisting of hourly or more frequent portions that are taken over a 24-hour period. A time-proportioned composite sample may be used upon approval of the Department if the permittee demonstrates it is representative of the discharge.

PART II

Section B. Monitoring Procedures

1. Representative Samples

Samples and measurements taken as required herein shall be representative of the volume and nature of the monitored discharge.

2. Test Procedures

Test procedures for the analysis of pollutants shall conform to regulations promulgated pursuant to Section 304(h) of the Federal Act (40 CFR Part 136 – Guidelines Establishing Test Procedures for the Analysis of Pollutants), unless specified otherwise in this permit. **Test procedures used shall be sufficiently sensitive to determine compliance with applicable effluent limitations.** Requests to use test procedures not promulgated under 40 CFR Part 136 for pollutant monitoring required by this permit shall be made in accordance with the Alternate Test Procedures regulations specified in 40 CFR 136.4. These requests shall be submitted to the Section Manager of the Permits Section, Water Resources Division, Michigan Department of Environment, Great Lakes, and Energy, P.O. Box 30458, Lansing, Michigan, 48909-7958. The permittee may use such procedures upon approval.

The permittee shall periodically calibrate and perform maintenance procedures on all analytical instrumentation at intervals to ensure accuracy of measurements. The calibration and maintenance shall be performed as part of the permittee's laboratory Quality Control/Quality Assurance program.

3. Instrumentation

The permittee shall periodically calibrate and perform maintenance procedures on all monitoring instrumentation at intervals to ensure accuracy of measurements.

4. Recording Results

For each measurement or sample taken pursuant to the requirements of this permit, the permittee shall record the following information: 1) the exact place, date, and time of measurement or sampling; 2) the person(s) who performed the measurement or sample collection; 3) the dates the analyses were performed; 4) the person(s) who performed the analyses; 5) the analytical techniques or methods used; 6) the date of and person responsible for equipment calibration; and 7) the results of all required analyses.

5. Records Retention

All records and information resulting from the monitoring activities required by this permit including all records of analyses performed and calibration and maintenance of instrumentation and recordings from continuous monitoring instrumentation shall be retained for a minimum of three (3) years, or longer if requested by the Regional Administrator or the Department.

PART II

Section C. Reporting Requirements

1. Start-up Notification

If the permittee will not discharge during the first 60 days following the effective date of this permit, the permittee shall notify the Department within 14 days following the effective date of this permit, and then 60 days prior to the commencement of the discharge.

2. Submittal Requirements for Self-Monitoring Data

Part 31 of the NREPA (specifically Section 324.3110(7)); and R 323.2155(2) of Part 21, Wastewater Discharge Permits, promulgated under Part 31 of the NREPA, allow the Department to specify the forms to be utilized for reporting the required self-monitoring data. Unless instructed on the effluent limitations page to conduct "Retained Self-Monitoring," the permittee shall submit self-monitoring data via the Department's MiWaters system.

The permittee shall utilize the information provided on the MiWaters website, located at <https://miwaters.deq.state.mi.us>, to access and submit the electronic forms. Both monthly summary and daily data shall be submitted to the Department no later than the 20th day of the month following each month of the authorized discharge period(s). The permittee may be allowed to submit the electronic forms after this date if the Department has granted an extension to the submittal date.

3. Retained Self-Monitoring Requirements

If instructed on the effluent limits page (or otherwise authorized by the Department in accordance with the provisions of this permit) to conduct retained self-monitoring, the permittee shall maintain a year-to-date log of retained self-monitoring results and, upon request, provide such log for inspection to the staff of the Department. Retained self-monitoring results are public information and shall be promptly provided to the public upon request.

The permittee shall certify, in writing, to the Department, on or before January 10th (April 1st for animal feeding operation facilities) of each year, that: 1) all retained self-monitoring requirements have been complied with and a year-to-date log has been maintained; and 2) the application on which this permit is based still accurately describes the discharge. With this annual certification, the permittee shall submit a summary of the previous year's monitoring data. The summary shall include maximum values for samples to be reported as daily maximums and/or monthly maximums and minimum values for any daily minimum samples.

Retained self-monitoring may be denied to a permittee by notification in writing from the Department. In such cases, the permittee shall submit self-monitoring data in accordance with Part II.C.2., above. Such a denial may be rescinded by the Department upon written notification to the permittee. Reissuance or modification of this permit or reissuance or modification of an individual permittee's authorization to discharge shall not affect previous approval or denial for retained self-monitoring unless the Department provides notification in writing to the permittee.

4. Additional Monitoring by Permittee

If the permittee monitors any pollutant at the location(s) designated herein more frequently than required by this permit, using approved analytical methods as specified above, the results of such monitoring shall be included in the calculation and reporting of the values required in the Discharge Monitoring Report. Such increased frequency shall also be indicated.

PART II

Section C. Reporting Requirements

Monitoring required pursuant to Part 41 of the NREPA or Rule 35 of the Mobile Home Park Commission Act (Act 96 of the Public Acts of 1987) for assurance of proper facility operation shall be submitted as required by the Department.

5. Compliance Dates Notification

Within 14 days of every compliance date specified in this permit, the permittee shall submit a *written* notification to the Department indicating whether or not the particular requirement was accomplished. If the requirement was not accomplished, the notification shall include an explanation of the failure to accomplish the requirement, actions taken or planned by the permittee to correct the situation, and an estimate of when the requirement will be accomplished. If a written report is required to be submitted by a specified date and the permittee accomplishes this, a separate written notification is not required.

6. Noncompliance Notification

Compliance with all applicable requirements set forth in the Federal Act, Parts 31 and 41 of the NREPA, and related regulations and rules is required. All instances of noncompliance shall be reported as follows:

- a. 24-Hour Reporting
Any noncompliance which may endanger health or the environment (including maximum and/or minimum daily concentration discharge limitation exceedances) shall be reported, verbally, within 24 hours from the time the permittee becomes aware of the noncompliance. A written submission shall also be provided within five (5) days.
- b. Other Reporting
The permittee shall report, in writing, all other instances of noncompliance not described in a. above at the time monitoring reports are submitted; or, in the case of retained self-monitoring, within five (5) days from the time the permittee becomes aware of the noncompliance.

Written reporting shall include: 1) a description of the discharge and cause of noncompliance; and 2) the period of noncompliance, including exact dates and times, or, if not yet corrected, the anticipated time the noncompliance is expected to continue, and the steps taken to reduce, eliminate and prevent recurrence of the noncomplying discharge.

7. Spill Notification

The permittee shall immediately report any release of any polluting material which occurs to the surface waters or groundwaters of the state, unless the permittee has determined that the release is not in excess of the threshold reporting quantities specified in the Part 5 Rules (R 324.2001 through R 324.2009 of the Michigan Administrative Code), by calling the Department at the number indicated on the second page of this permit (or, if this is a general permit, on the COC); or, if the notice is provided after regular working hours, call the Department's 24-hour Pollution Emergency Alerting System telephone number, 1-800-292-4706 (calls from **out-of-state** dial 1-517-373-7660).

Within ten (10) days of the release, the permittee shall submit to the Department a full written explanation as to the cause of the release, the discovery of the release, response (clean-up and/or recovery) measures taken, and preventive measures taken or a schedule for completion of measures to be taken to prevent reoccurrence of similar releases.

PART II**Section C. Reporting Requirements****8. Upset Noncompliance Notification**

If a process "upset" (defined as an exceptional incident in which there is unintentional and temporary noncompliance with technology based permit effluent limitations because of factors beyond the reasonable control of the permittee) has occurred, the permittee who wishes to establish the affirmative defense of upset, shall notify the Department by telephone within 24 hours of becoming aware of such conditions; and within five (5) days, provide in writing, the following information:

- a. that an upset occurred and that the permittee can identify the specific cause(s) of the upset;
- b. that the permitted wastewater treatment facility was, at the time, being properly operated and maintained (note that an upset does not include noncompliance to the extent caused by operational error, improperly designed treatment facilities, inadequate treatment facilities, lack of preventive maintenance, or careless or improper operation); and
- c. that the permittee has specified and taken action on all responsible steps to minimize or correct any adverse impact in the environment resulting from noncompliance with this permit.

No determination made during administrative review of claims that noncompliance was caused by upset, and before an action for noncompliance, is final administrative action subject to judicial review.

In any enforcement proceedings, the permittee, seeking to establish the occurrence of an upset, has the burden of proof.

9. Bypass Prohibition and Notification

- a. Bypass Prohibition
Bypass is prohibited, and the Department may take an enforcement action, unless:
 - 1) bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;
 - 2) there were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime. This condition is not satisfied if adequate backup equipment should have been installed in the exercise of reasonable engineering judgment to prevent a bypass; and
 - 3) the permittee submitted notices as required under 9.b. or 9.c. below.
- b. Notice of Anticipated Bypass
If the permittee knows in advance of the need for a bypass, it shall submit prior notice to the Department, if possible at least ten (10) days before the date of the bypass, and provide information about the anticipated bypass as required by the Department. The Department may approve an anticipated bypass, after considering its adverse effects, if it will meet the three (3) conditions listed in 9.a. above.
- c. Notice of Unanticipated Bypass
The permittee shall submit notice to the Department of an unanticipated bypass by calling the Department at the number indicated on the second page of this permit (if the notice is provided after regular working hours, use the following number: 1-800-292-4706) as soon as possible, but no later than 24 hours from the time the permittee becomes aware of the circumstances.

PART II

Section C. Reporting Requirements

- d. **Written Report of Bypass**
A written submission shall be provided within five (5) working days of commencing any bypass to the Department, and at additional times as directed by the Department. The written submission shall contain a description of the bypass and its cause; the period of bypass, including exact dates and times, and if the bypass has not been corrected, the anticipated time it is expected to continue; steps taken or planned to reduce, eliminate, and prevent reoccurrence of the bypass; and other information as required by the Department.
- e. **Bypass Not Exceeding Limitations**
The permittee may allow any bypass to occur which does not cause effluent limitations to be exceeded, but only if it also is for essential maintenance to ensure efficient operation. These bypasses are not subject to the provisions of 9.a., 9.b., 9.c., and 9.d., above. This provision does not relieve the permittee of any notification responsibilities under Part II.C.11. of this permit.
- f. **Definitions**
 - 1) Bypass means the intentional diversion of waste streams from any portion of a treatment facility.
 - 2) Severe property damage means substantial physical damage to property, damage to the treatment facilities which causes them to become inoperable, or substantial and permanent loss of natural resources which can reasonably be expected to occur in the absence of a bypass. Severe property damage does not mean economic loss caused by delays in production.

10. Bioaccumulative Chemicals of Concern (BCC)

Consistent with the requirements of R 323.1098 and R 323.1215 of the Michigan Administrative Code, the permittee is prohibited from undertaking any action that would result in a lowering of water quality from an increased loading of a BCC unless an increased use request and antidegradation demonstration have been submitted and approved by the Department.

11. Notification of Changes in Discharge

The permittee shall notify the Department, in writing, as soon as possible but no later than 10 days of knowing, or having reason to believe, that any activity or change has occurred or will occur which would result in the discharge of: 1) detectable levels of chemicals on the current Michigan Critical Materials Register, priority pollutants or hazardous substances set forth in 40 CFR 122.21, Appendix D, or the Pollutants of Initial Focus in the Great Lakes Water Quality Initiative specified in 40 CFR 132.6, Table 6, which were not acknowledged in the application or listed in the application at less than detectable levels; 2) detectable levels of any other chemical not listed in the application or listed at less than detection, for which the application specifically requested information; or 3) any chemical at levels greater than five times the average level reported in the complete application (see the first page of this permit, for the date(s) the complete application was submitted). Any other monitoring results obtained as a requirement of this permit shall be reported in accordance with the compliance schedules.

PART II

Section C. Reporting Requirements

12. Changes in Facility Operations

Any anticipated action or activity, including but not limited to facility expansion, production increases, or process modification, which will result in new or increased loadings of pollutants to the receiving waters must be reported to the Department by a) submission of an increased use request (application) and all information required under R 323.1098 (Antidegradation) of the Water Quality Standards or b) by notice if the following conditions are met: 1) the action or activity will not result in a change in the types of wastewater discharged or result in a greater quantity of wastewater than currently authorized by this permit; 2) the action or activity will not result in violations of the effluent limitations specified in this permit; 3) the action or activity is not prohibited by the requirements of Part II.C.10.; and 4) the action or activity will not require notification pursuant to Part II.C.11. Following such notice, the permit or, if applicable, the facility's COC may be modified according to applicable laws and rules to specify and limit any pollutant not previously limited.

13. Transfer of Ownership or Control

In the event of any change in control or ownership of facilities from which the authorized discharge emanates, the permittee shall submit to the Department 30 days prior to the actual transfer of ownership or control a written agreement between the current permittee and the new permittee containing: 1) the legal name and address of the new owner; 2) a specific date for the effective transfer of permit responsibility, coverage and liability; and 3) a certification of the continuity of or any changes in operations, wastewater discharge, or wastewater treatment.

If the new permittee is proposing changes in operations, wastewater discharge, or wastewater treatment, the Department may propose modification of this permit in accordance with applicable laws and rules.

14. Operations and Maintenance Manual

For wastewater treatment facilities that serve the public (and are thus subject to Part 41 of the NREPA), Section 4104 of Part 41 and associated Rule 2957 of the Michigan Administrative Code allow the Department to require an Operations and Maintenance (O&M) Manual from the facility. An up-to-date copy of the O&M Manual shall be kept at the facility and shall be provided to the Department upon request. The Department may review the O&M Manual in whole or in part at its discretion and require modifications to it if portions are determined to be inadequate.

At a minimum, the O&M Manual shall include the following information: permit standards; descriptions and operation information for all equipment; staffing information; laboratory requirements; record keeping requirements; a maintenance plan for equipment; an emergency operating plan; safety program information; and copies of all pertinent forms, as-built plans, and manufacturer's manuals.

Certification of the existence and accuracy of the O&M Manual shall be submitted to the Department at least sixty days prior to start-up of a new wastewater treatment facility. Recertification shall be submitted sixty days prior to start-up of any substantial improvements or modifications made to an existing wastewater treatment facility.

PART II

Section C. Reporting Requirements

15. Signatory Requirements

All applications, reports, or information submitted to the Department in accordance with the conditions of this permit and that require a signature shall be signed and certified as described in the Federal Act and the NREPA.

The Federal Act provides that any person who knowingly makes any false statement, representation, or certification in any record or other document submitted or required to be maintained under this permit, including monitoring reports or reports of compliance or noncompliance, shall, upon conviction, be punished by a fine of not more than \$10,000 per violation, or by imprisonment for not more than 6 months per violation, or by both.

The NREPA (Section 3115(2)) provides that a person who at the time of the violation knew or should have known that he or she discharged a substance contrary to this part, or contrary to a permit, COC, or order issued or rule promulgated under this part, or who intentionally makes a false statement, representation, or certification in an application for or form pertaining to a permit or COC or in a notice or report required by the terms and conditions of an issued permit or COC, or who intentionally renders inaccurate a monitoring device or record required to be maintained by the Department, is guilty of a felony and shall be fined not less than \$2,500.00 or more than \$25,000.00 for each violation. The court may impose an additional fine of not more than \$25,000.00 for each day during which the unlawful discharge occurred. If the conviction is for a violation committed after a first conviction of the person under this subsection, the court shall impose a fine of not less than \$25,000.00 per day and not more than \$50,000.00 per day of violation. Upon conviction, in addition to a fine, the court in its discretion may sentence the defendant to imprisonment for not more than 2 years or impose probation upon a person for a violation of this part. With the exception of the issuance of criminal complaints, issuance of warrants, and the holding of an arraignment, the circuit court for the county in which the violation occurred has exclusive jurisdiction. However, the person shall not be subject to the penalties of this subsection if the discharge of the effluent is in conformance with and obedient to a rule, order, permit, or COC of the Department. In addition to a fine, the attorney general may file a civil suit in a court of competent jurisdiction to recover the full value of the injuries done to the natural resources of the state and the costs of surveillance and enforcement by the state resulting from the violation.

16. Electronic Reporting

Upon notice by the Department that electronic reporting tools are available for specific reports or notifications, the permittee shall submit electronically all such reports or notifications as required by this permit.

PART II

Section D. Management Responsibilities

1. Duty to Comply

All discharges authorized herein shall be consistent with the terms and conditions of this permit. The discharge of any pollutant identified in this permit, more frequently than, or at a level in excess of, that authorized, shall constitute a violation of the permit.

It is the duty of the permittee to comply with all the terms and conditions of this permit. Any noncompliance with the Effluent Limitations, Special Conditions, or terms of this permit constitutes a violation of the NREPA and/or the Federal Act and constitutes grounds for enforcement action; for permit or Certificate of Coverage (COC) termination, revocation and reissuance, or modification; or denial of an application for permit or COC renewal.

It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

2. Operator Certification

The permittee shall have the waste treatment facilities under direct supervision of an operator certified at the appropriate level for the facility certification by the Department, as required by Sections 3110 and 4104 of the NREPA. Permittees authorized to discharge storm water shall have the storm water treatment and/or control measures under direct supervision of a storm water operator certified by the Department, as required by Section 3110 of the NREPA.

3. Facilities Operation

The permittee shall, at all times, properly operate and maintain all treatment or control facilities or systems installed or used by the permittee to achieve compliance with the terms and conditions of this permit. Proper operation and maintenance includes adequate laboratory controls and appropriate quality assurance procedures.

4. Power Failures

In order to maintain compliance with the effluent limitations of this permit and prevent unauthorized discharges, the permittee shall either:

- a. provide an alternative power source sufficient to operate facilities utilized by the permittee to maintain compliance with the effluent limitations and conditions of this permit; or
- b. upon the reduction, loss, or failure of one or more of the primary sources of power to facilities utilized by the permittee to maintain compliance with the effluent limitations and conditions of this permit, the permittee shall halt, reduce or otherwise control production and/or all discharge in order to maintain compliance with the effluent limitations and conditions of this permit.

5. Adverse Impact

The permittee shall take all reasonable steps to minimize or prevent any adverse impact to the surface waters or groundwaters of the state resulting from noncompliance with any effluent limitation specified in this permit including, but not limited to, such accelerated or additional monitoring as necessary to determine the nature and impact of the discharge in noncompliance.

PART II

Section D. Management Responsibilities

6. Containment Facilities

The permittee shall provide facilities for containment of any accidental losses of polluting materials in accordance with the requirements of the Part 5 Rules (R 324.2001 through R 324.2009 of the Michigan Administrative Code). For a Publicly Owned Treatment Work (POTW), these facilities shall be approved under Part 41 of the NREPA.

7. Waste Treatment Residues

Residuals (i.e. solids, sludges, biosolids, filter backwash, scrubber water, ash, grit, or other pollutants or wastes) removed from or resulting from treatment or control of wastewaters, including those that are generated during treatment or left over after treatment or control has ceased, shall be disposed of in an environmentally compatible manner and according to applicable laws and rules. These laws may include, but are not limited to, the NREPA, Part 31 for protection of water resources, Part 55 for air pollution control, Part 111 for hazardous waste management, Part 115 for solid waste management, Part 121 for liquid industrial wastes, Part 301 for protection of inland lakes and streams, and Part 303 for wetlands protection. Such disposal shall not result in any unlawful pollution of the air, surface waters or groundwaters of the state.

8. Right of Entry

The permittee shall allow the Department, any agent appointed by the Department, or the Regional Administrator, upon the presentation of credentials and, for animal feeding operation facilities, following appropriate biosecurity protocols:

- a. to enter upon the permittee's premises where an effluent source is located or any place in which records are required to be kept under the terms and conditions of this permit; and
- b. at reasonable times to have access to and copy any records required to be kept under the terms and conditions of this permit; to inspect process facilities, treatment works, monitoring methods and equipment regulated or required under this permit; and to sample any discharge of pollutants.

9. Availability of Reports

Except for data determined to be confidential under Section 308 of the Federal Act and Rule 2128 (R 323.2128 of the Michigan Administrative Code), all reports prepared in accordance with the terms of this permit, shall be available for public inspection at the offices of the Department and the Regional Administrator. As required by the Federal Act, effluent data shall not be considered confidential. Knowingly making any false statement on any such report may result in the imposition of criminal penalties as provided for in Section 309 of the Federal Act and Sections 3112, 3115, 4106 and 4110 of the NREPA.

10. Duty to Provide Information

The permittee shall furnish to the Department, within a reasonable time, any information which the Department may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit or the facility's COC, or to determine compliance with this permit. The permittee shall also furnish to the Department, upon request, copies of records required to be kept by this permit.

Where the permittee becomes aware that it failed to submit any relevant facts in a permit application, or submitted incorrect information in a permit application or in any report to the Department, it shall promptly submit such facts or information.

PART II**Section E. Activities Not Authorized by This Permit****1. Discharge to the Groundwaters**

This permit does not authorize any discharge to the groundwaters. Such discharge may be authorized by a groundwater discharge permit issued pursuant to the NREPA.

2. POTW Construction

This permit does not authorize or approve the construction or modification of any physical structures or facilities at a POTW. Approval for the construction or modification of any physical structures or facilities at a POTW shall be by permit issued under Part 41 of the NREPA.

3. Civil and Criminal Liability

Except as provided in permit conditions on "Bypass" (Part II.C.9. pursuant to 40 CFR 122.41(m)), nothing in this permit shall be construed to relieve the permittee from civil or criminal penalties for noncompliance, whether or not such noncompliance is due to factors beyond the permittee's control, such as accidents, equipment breakdowns, or labor disputes.

4. Oil and Hazardous Substance Liability

Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties to which the permittee may be subject under Section 311 of the Federal Act except as are exempted by federal regulations.

5. State Laws

Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties established pursuant to any applicable state law or regulation under authority preserved by Section 510 of the Federal Act.

6. Property Rights

The issuance of this permit does not convey any property rights in either real or personal property, or any exclusive privileges, nor does it authorize violation of any federal, state or local laws or regulations, nor does it obviate the necessity of obtaining such permits, including any other Department of Environment, Great Lakes, and Energy permits, or approvals from other units of government as may be required by law.

Attachment G

MPSC Case No, U-21090, Order approving settlement
(June 23, 2022)

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

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

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

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

ORDER APPROVING SETTLEMENT AGREEMENT

I. Procedural History

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

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

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

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

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

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

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

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

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

II. Applicable Law

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

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

III. Proposed Settlement Agreement

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

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

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

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

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

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

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

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

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

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

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

i. In that approval proceeding, the Commission shall: (i) confirm whether the solicitation process followed by the Company is consistent with the requirements of the Settlement Agreement; (ii) grant approval of the recovery of the costs associated with the selected project(s) pursuant to applicable law or make a preliminary finding that the costs associated 7 with the project(s) that

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

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

Id., pp. 6-7.

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

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

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

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

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

IV. Evidentiary Record

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

A. Direct Testimony

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Mr. Jester concludes that “[t]he settlement agreement in this case continues and significantly extends the progress of the settlement [agreement] in [Case No.] U-20165.” 10 Tr 4341.

Mr. Jester posits that the settlement agreement is “supported by the great weight of evidence in the record of this case and consistent with many of the findings and recommendations in the PFD.”

10 Tr 4342. Thus, Mr. Jester recommends the Commission approve the proposed settlement agreement.

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

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

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

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

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

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

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

3. Energy Michigan

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

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

4. The Commission Staff

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

5. Biomass Merchant Plants

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

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

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

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

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

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

10 Tr 4278.

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

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

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

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

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

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

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

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

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

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

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

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

6. Wolverine Power Supply Cooperative

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

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

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

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

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

B. Rebuttal Testimony

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

3. The Commission Staff

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

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

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

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

retirement until May 31, 2031. Mr. Proudfoot posits that Consumers “was originally proposing to retire approximately 2800 MW (nameplate) generation from MISO Zone 7” while the settlement agreement “only retires a portion of that amount, approximately 1500 MW” 10 Tr 4405.

Further, Mr. Proudfoot notes that along with the commitment to retire the entire Campbell plant, Consumers “is proposing to add approximately 1176 MW to Zone 7 through the acquisition of the Covert Power Plant.” 10 Tr 4405. Further, Mr. Proudfoot provides that Consumers “continues its solar build out and is expected to add 300 MW of solar resources in 2023, 500 MW of solar resources in 2024, and 500 MW of solar resources in 2025[.]” noting that under the current MISO ELCC construct, “that is approximately 400 ZRC’s [sic] of new resources within MISO Zone 7.” 10 Tr 4406 (footnote omitted). Mr. Proudfoot adds that the one-time solicitation for 700 MW set forth in the settlement agreement is additional to the resources outlined above. 10 Tr 4406.

Mr. Proudfoot concludes that the “Staff does not believe the [settlement agreement] is likely to result in the Company being short on capacity in 2025.” 10 Tr 4406. Mr. Proudfoot opines that the 7.4% reserve margin used by Consumers in its Capacity Demonstration in Case No. U-21099 is reasonable as it “comes directly from the 2022-2023 MISO Loss of Load Expectation (LOLE) Study Report.” 10 Tr 4406 (footnote omitted).

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

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

4. Biomass Merchant Plants

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

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

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

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

5. Wolverine Power Supply Cooperative

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

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

10 Tr 4312. Mr. King posits that, "the second tranche of 200 ZRCs are likely to be procured from

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

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

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

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

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

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

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

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

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

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

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

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

7. Consumers

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

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

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

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

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

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

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

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

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

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

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

10 Tr 4136.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

C. Initial Briefs

1. Energy Michigan

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

3. Mackinac Center for Public Policy

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

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

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

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

Mackinac further expresses concern that:

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

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

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

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

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

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

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

Id., p. 21.

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

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

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

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

5. Michigan Department of Attorney General

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

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

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

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

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

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

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

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

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

7. Hemlock Semiconductor Operations, LLC

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

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

8. The Commission Staff

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

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

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

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

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

9. Consumers Energy Company

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

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

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

Consumers reiterates its testimony that:

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

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

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

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

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

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

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

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

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

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

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

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

10. The Biomass Merchant Plants

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

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

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

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

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

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

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

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

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

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

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

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

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

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

11. Citizens Utility Board of Michigan

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

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

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

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

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

12. Wolverine Power Supply Cooperative

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

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

Id., p. 3 (footnote omitted).

WPSC states that:

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

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

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

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

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

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

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

Id., p. 10.

In addition, WPSC avers that the settlement agreement inappropriately requires Consumers to be treated as an island rather than an integrated and interconnected participant in the Michigan electric grid. WPSC argues that “[g]iven the likely capacity shortfall in Zone 7, the [settlement agreement’s] failure to address transmission deficiencies will exacerbate the problems created by hastily retiring generation resources. If one of the few existing ties fail or export capability from other areas is reduced, the only other option will be load shed.” *Id.*, p. 11 (footnote omitted).

WPSC concludes that, under Rule 431, the Commission must deny the settlement agreement as it “is not supported by *any* evidence within the record, and certainly is not supported by *substantial* evidence on the record” but rather that the record demonstrates additional modeling and analysis is needed to support an early retirement of Campbell Unit 3. *Id.*, p. 12 (emphasis in original). WPSC further states that “[r]ushing the retirement of Campbell Unit 3 may allow the Commission to continue forward with its admirable goal of reducing Michigan’s carbon emissions, but it will come at the risk of electric reliability and related health and safety of

Michiganders.” *Id.* WPSC avers that the settlement agreement does not reflect the most reasonable and prudent path and that the Commission should “require Consumers to keep Campbell Unit 3 in operation, at least until Consumers can present hard data that verifies that Campbell Unit 3 can be retired without jeopardizing reliability and, as the PFD notes, Consumers has not modeled or analyzed these issues sufficiently.” *Id.*, p. 13.

13. Urban Core Collective

UCC filed a statement in support of the settlement agreement in lieu of an initial brief to reaffirm its initial support as a signatory to the settlement agreement. *See*, Case No. U-21090, filing #U-21090-0857.

D. Reply Briefs

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

In reply to Energy Michigan, MNS argues that Energy Michigan errs in positing that the considerations under MCL 460.6t(8) somehow trump the Rule 431 criteria. MNS’ reply brief, pp. 2-3. MNS notes that the Michigan Administrative Procedures Act (APA) also addresses settlements and provides that contested cases may end in settlement when agreed to by the parties in MCL 24.278(2). *Id.*, p. 3. MNS contends that Rule 431 implements this statutory requirement. While agreeing with Energy Michigan that it is important to harmonize the IRP statute and Rule 431, MNS contends that Energy Michigan’s reading of MCL 460.6t(8) would make applying the requirements of Rule 431 an “empty exercise.” *Id.*, p. 4. MNS further contends that Energy Michigan’s argument conflicts with the Commission’s approval of the contested settlement in Case No. U-20165. *Id.* (citing June 7, 2019 order in Case No. U-20165, p. 76 (June 7 order); *see also*, June 7 order, p. 91).

MNS states that it addressed Energy Michigan’s resource adequacy and pricing arguments in its initial brief, and notes that Energy Michigan was included in all settlement discussions, asserting that Energy Michigan was included in multiple emails regarding the settlement conference which took place in February 2022. MNS’ reply brief, p. 5.

In reply to WPSC, MNS again argues (as it did in its initial brief) that, contrary to WPSC’s assertions, the settlement agreement will actually improve resource adequacy in Zone 7. MNS again points to the 1,114 ZRCs from the Covert gas plant, 71 ZRCs of new battery storage, 250 ZRCs of new solar generation, and 94 ZRCs of new demand side resources, and states that “[e]ven with the retirement of the Campbell coal units, these resource additions will result in an overall net increase in Zone 7 resources.” *Id.*, p. 7 (citing 9 Tr 5-6, 10 Tr 4350, and Settlement Agreement, Sections 1-3); *see also*, 10 Tr 4405-4406. MNS further argues that WPSC’s repeated citations to the PFD for support are inapposite since the PFD evaluated the original PCA, which presented actual resource adequacy concerns. MNS’ reply brief, pp. 8-9.

MNS contends that the Commission should not consider the websites and news stories cited by WPSC regarding the PRMR because they are not part of the record, and, in any case, Mr. Jester, Mr. Proudfoot, and Mr. Clark rebutted these concerns. MNS’ reply brief, p. 10 (quoting 10 Tr 4406-4407) (citing 10 Tr 4358-4359 and 4227-4228). MNS notes that Mr. Proudfoot testified that:

The reserve margin used by the Company in its capacity demonstration for 2025 comes directly from the 2022-2023 MISO Loss of Load Expectation (LOLE) Study Report. It is also worth noting that assuming a constant reserve margin of 8.7% instead of 7.4% would represent about 100 MW of additional obligation to the Company. The differences between Karn Units 3 & 4 and the CMS capacity is still likely enough to cover this difference, even without counting any additional capacity from the one-time solicitation.

MNS' reply brief, p. 10 (quoting 10 Tr 4406-4407). MNS asserts that WPSC's claims about Consumers being capacity negative are simply untrue as shown by the list of ZRCs described above, and states that "Consumers would still have a surplus even if both tranches of the one-time solicitation fail entirely: in that extremely unlikely scenario, Consumers would still have a 514 ZRC surplus in 2025/26." MNS' reply brief, p. 11 (citing 10 Tr 4354). Finally, on this issue, MNS avers that Mr. Jester showed that Mr. King's calculations were incorrect because Mr. King assumed that Karn Units 3 and 4 would be operating in the 2025/2026 planning year. MNS' reply brief, p. 12 (citing 10 Tr 4355). MNS notes that WPSC fails to cite to any record evidence showing that the retirement of Campbell Unit 3 in 2025 is unsupported. MNS' reply brief, p. 12.

In reply to the BMPs, MNS argues that their claims regarding a lower ELCC are exaggerated and inaccurate, and states that the BMPs mischaracterized Mr. Clark's testimony where he indicated that the ELCC "could" drop. MNS' reply brief, p. 15 (citing 5 Tr 1123) (emphasis omitted). Additionally, MNS notes that several witnesses refuted this argument, including Mr. Clark himself when he testified that the ELCC has been stable for six years and no changes are pending. MNS' reply brief, pp. 15-16 (citing 10 Tr 4226-4227, 4236). MNS observes that Mr. Blumenstock testified that even applying the BMPs' 30% ELCC figure, there would be no shortfall for eight years. MNS' reply brief, p. 16 (citing 10 Tr 4142-4143). Additionally, MNS notes, Mr. Jester showed that the BMPs' figure comes from an exploratory modeling exercise. MNS' reply brief, p. 16 (citing 10 Tr 4365-4366).

Finally, MNS objects to the BMPs' appeal of certain evidentiary rulings made by the ALJ, noting that the BMPs fail to cite to any legal authority in support of their appeal. MNS argues that a party may not "simply announce a position on appeal and leave it to the reviewing body to search for authority to support the party's position." MNS' reply brief, p. 18 (citing *Wilson v*

Taylor, 457 Mich 232, 243; 577 NW2d 100 (1998)). MNS contends that the BMPs’ counsel misrepresented how long his cross-examination of Mr. Blumenstock would last, and then offered questions on irrelevant subjects. MNS’ reply brief, p. 18 (citing 10 Tr 4193, 4211). MNS contends that, under MCL 24.280(1)(d), the presiding officer is empowered to regulate the course of the proceedings. MNS avers that the ALJ’s rulings were reasonable and well within her authority and should be affirmed. MNS’ reply brief, pp. 18-19.

In reply to Mackinac, MNS urges the Commission to give no weight to Mackinac’s brief. As an initial matter, MNS alleges that Mackinac did not comply with the requirements of Rule 431(3) when it filed its objection, because it failed to state its objections with particularity or specify how it would be adversely affected by the settlement agreement. Additionally, MNS argues, Mackinac’s initial brief is mostly cut-and-pasted from its exceptions, and the exceptions were focused on the PFD and the original PCA – a different factual scenario. MNS notes that Mackinac’s initial brief is filled with unsupported assertions and relies heavily on news stories and website links that are not part of the record, contrary to the requirements of the APA. MNS’ reply brief, pp. 20-21 (citing MCL 24.276 and 24.285). Moreover, MNS posits, DR and CVR programs are not designed to cut off customers from electricity. MNS describes Mackinac as “ill-informed.” MNS’ reply brief, pp. 21-22.

2. The Commission Staff

In reply, the Staff states that MCL 460.6t(8) provides seven factors for the Commission to balance when determining if the statutory requirements are satisfied. The Staff states that the settlement agreement is a compromise made by parties with a wide variety of interests and is reasonable and prudent. The Staff also contends that “the settlement agreement also balances the

reliability needs of MISO Zone 7 with Consumers’ ability to provide energy and capacity to its customers.” Staff’s reply brief, p. 2 (citing Staff’s initial brief, pp. 3-5).

Regarding resource adequacy concerns, the Staff replies that the PCA, as modified by the settlement agreement, is reasonable and prudent and balances the reliability needs of Zone 7. *See*, Staff’s reply brief, p. 3. Continuing, the Staff avers that “[g]iven the capacity from Karn Units 3 and 4, additional solar resources, and the up to 700 MW one-time solicitation set forth in the settlement agreement, Staff . . . does not believe Consumers is likely to be short on capacity in 2025” and that “this capacity is more than sufficient to make up the capacity assumed for the CMS [plants] contemplated in Consumers’ original IRP and may even be sufficient to meet Consumers’ previous planning reserve margin of 8.7% that [WPSC] referenced in direct testimony.” *Id.*, pp. 3-4 (citing 10 Tr 4306, 4406-4407).

In response to the BMPs’ testimony regarding a deficiency in 2035, the Staff replies:

that the IRP statute requires 5-, 10-, and 15-year projections of the utility’s load obligation and plan, but Commission cost approval for investments or resources used to meet energy and capacity need is only presumed reasonable and prudent for those actions commenced within three years of Commission approval of the IRP. MCL 460.6t(3), (11).

Staff’s reply brief, p. 4. Therefore, the Staff avers that there is a likelihood that changes will occur between the approval of the IRP and the long-term projections as further reinforced by the requirement in MCL 460.6t(20) for regulated utilities make an IRP filing at least every 5 years. *Id.*

Finally, the Staff avers that Mackinac’s “initial brief contains many footnotes citing to material that was not offered into evidence or addressed in testimony” and that Mackinac “did not file testimony in either phase of this proceeding and filed a one-page objection to the settlement agreement.” *Id.*, p. 6. Therefore, the Staff requests that the Commission disregard the portions of

Mackinac's briefing supporting its objections to the settlement agreement not supported on the record.

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

In reply to the BMPs, the CEOs point out that the BMPs' request to modify the settlement agreement is a form of relief that is unavailable because the settlement agreement is not severable, thus modification would result in rejection of the entire agreement. CEOs' reply brief, p. 1, n. 1. The CEOs further aver that the BMPs' contracts should not be extended in any case due to the non-carbon pollution associated with their operations as well as the documented environmental justice concerns. CEOs' reply brief, p. 2. The CEOs note that one of the directives issued by Governor Whitmer pursuant to ED 2020-10 requires the Michigan Department of Environment, Great Lakes, and Energy to include considerations of environmental justice and public health when issuing advisory opinions in IRP proceedings. *Id.*, pp. 2-3. The CEOs submit that they provided extensive evidence on the record showing the non-carbon air pollution emissions and environmental justice concerns associated with the BMPs, stating that:

[s]ome of these plants co-fire tire-derived fuels, and most of them have higher emission rates of PM_{2.5} and NO_x than even Consumers' coal plants. (Krieger, 7 TR 2383). Moreover, eight of nine plants are located in areas considered more low-income than the state median. (Krieger, 7 TR 2383). The 38,000 people living near the Genesee plant rank in the 89th percentile for low-income populations, 86th percentile for populations of color, and 83rd percentile on the EJ [Environmental Justice] Index. (Krieger, 7 TR 2384). "[B]iomass power plants are likely to have higher air pollutant emissions rates per unit energy produced."

CEOs' reply brief, p. 3 (quoting 7 Tr 2397) (emphasis omitted). The CEOs note that Dr. Bilsback concluded that the emissions rates of biomass plants are comparable to fossil-fuel fired plants. CEOs' reply brief, p. 4 (citing 7 Tr 2418). The CEOs contend that simply because a fuel source

may be renewable does not mean that it will not have health impacts; and they note that the BMPs did not rebut this testimony. CEOs' reply brief, p. 4.

The CEOs also regard the BMPs' argument that the settlement agreement is a ploy to allow for the construction of a natural gas plant as far-fetched. The CEOs point out that the settlement agreement (Section 6.b.ii.) limits the second tranche to "intermittent resources and dispatchable, nonintermittent clean capacity resources (including battery storage resources)," which could not be reasonably interpreted to include natural gas. *Id.* (quoting Settlement Agreement, p. 6). The CEOs further note that they would not be signatories to a settlement agreement that contemplates the construction of a new gas plant. CEOs' reply brief, p. 5 (citing 7 Tr 2354 and 10 Tr 4347). The CEOs contend that the land use concerns raised by the BMPs do not appear to relate to ED 2020-10. CEOs' reply brief, pp. 5-6.

The CEOs further argue that WPSC and the BMPs attempt to use scare tactics based on market information. The CEOs assert that Consumers used an appropriate capacity factor in its modeling, stating that, in reference to the BMPs' evidence, "[a]s Company witness Battaglia explained on rebuttal, the information shown in BMP-6 is presented in DC, rather than AC, and therefore does not present a comparable capacity factor to that used by the Company in modeling. (Battaglia Direct, 5 TR 1217:4-12)." CEOs' reply brief, p. 7. The CEOs also note that the BMPs focused on the wrong witness with respect to their ELCC arguments, as the solar capacity factor was covered by Mr. Kapala and not Mr. Battaglia (and this mistake was noted by the ALJ as well). *Id.*, p. 8 (citing 6 Tr 1296-1297; 7 Tr 1822). The CEOs further assert that WPSC's theory that Consumers will be unable to acquire 250 ZRCs of solar by 2025 was refuted by Mr. Lucas. CEOs' reply brief, p. 9 (citing 10 Tr 4382-4384). They also cite to the testimony of Mr. Clark and Mr. Jester refuting the notion that the ELCC poses an unreasonable risk to the settlement

agreement. CEOs' reply brief, p. 9 (citing 10 Tr 4236, 4367-4368). Finally, the CEOs point to Mr. Blumenstock's testimony that Karn Units 3 and 4 are unlikely to become system support resources. CEOs' reply brief, p. 10 (citing 10 Tr 4152).

The CEOs assert that Mackinac's arguments are improper and redundant. CEOs' reply brief, p. 10.

4. Consumers Energy Company

Consumers initially provides an overview of the arguments of the signatories to the settlement agreement reiterating its position that the settlement agreement is in the public interest, was the result of good-faith negotiation, and that the outcome is the most reasonable and prudent means of meeting the company's energy and capacity needs. Consumers' reply brief, pp. 3-5.

Consumers argues that issues raised by WPSC with regard to reliability and resource adequacy concerns have been addressed by the company's initial brief. Specifically, Consumers states that "[WPSC]'s claim . . . that the one-time solicitation will likely not create new [MISO LRZ] 7 capacity, is of no consequence" for the reasons set forth in its initial brief. *Id.*, p. 6. Consumers argues that "[t]he purpose of the one-time solicitation is to help replace the capacity and energy lost when Consumers Energy retires [Campbell] Units 1, 2, and 3 in 2025." *Id.* Consumers repeats that "[t]he Company is not required to provide capacity for [WPSC] or any other [LSEs] in LRZ 7." *Id.* Consumers states that WPSC's arguments that the settlement agreement will reduce reliability in LRZ 7 are "without merit" as outlined in its initial brief and WPSC has "failed to provide information showing any purported negative impact on [WPSC]" *Id.*, p. 7. Consumers reiterates that the settlement agreement will "bring at least 2,084 ZRCs into MISO's LRZ 7 and retire only approximately 1,400 ZRCs of capacity, with a net addition for LRZ 7 of nearly 700 ZRCs." *Id.* (footnote omitted). In response to WPSC's claims that the company's

PRMR will increase rather than decrease, Consumers argues that it has “fully supported its projected PRMR decrease” in its initial brief. *Id.* Consumers argues that WPSC’s claims that the one-time solicitation is “speculative and not supported by the record” are “meritless” and “Consumers Energy projects sufficient capacity for planning year 2025-2026, even without the additional 700 ZRCs of capacity proposed to be acquired via the solicitation, and many possible sources could fill the 700 ZRCs once the bidding commences.” *Id.*, p. 8 (quoting WPSC’s initial brief, p. 9).

Consumers addresses WPSC’s claim that the settlement agreement would “treat Consumers Energy as an ‘island,’ and that a capacity shortfall would affect [WPSC] and other LSEs in the state.” Consumers reply brief, p. 8 (quoting WPSC’s initial brief, p. 10). Consumers asserts that:

Michigan law contemplates that each electric provider plan to serve its own projected loads; it does not require electric providers to serve other electric providers’ loads, unless a utility is required to provide backup capacity under the state reliability mechanism in situations in which alternative electric suppliers fail to demonstrate compliance with their own four-year forward capacity obligations.

Consumers reply brief, p. 8 (citing MCL 460.6w). Consumers discredits WPSC’s claims that the record does not support the settlement agreement. *See*, Consumers’ reply brief, p. 9.

Turning to Energy Michigan’s arguments, Consumers first agrees with Energy Michigan’s contention that “the Commission Rule 431 standards for approving a contested settlement must harmonize with Section 6t(8) [of Act 341], and cannot overrule it or provide a ‘different and weaker approval standard.’” Consumers reply brief, p. 9 (quoting Energy Michigan’s initial brief, p. 2). Consumers posits that the settlement agreement “meets all criteria for approval contained in MCL 460.6t(8) and Commission Rule 431.” Consumers reply brief, p. 9.

Consumers addresses Energy Michigan’s assertion that company testimony stating “that ‘Consumers Energy is not responsible to ensure the reliability of Zone 7 beyond its own capacity

obligations’ indicates that the Company has changed its position, given that Mr. Clark described the IRP as the best plan ‘for Michigan.’” *Id.*, p. 10 (quoting Energy Michigan’s initial brief, p. 3).

Consumers asserts that it has not changed its position. Specifically, Consumers states that:

The IRP, as set forth in the Settlement Agreement, remains the best plan for Michigan, as it will meet its customers’ energy needs, will satisfy the Company’s PRMR obligations within LRZ 7, and further the Company’s goal to be carbon neutral by 2040 and retire all coal generation by 2025. Having the best plan for Michigan does not mean that Consumers Energy must single-handedly supply sufficient capacity for every other utility’s expected load in Michigan. It means having a plan that meets all of Consumers Energy’s customers’ capacity needs in a manner that avoids unnecessary environmental impacts that affect the whole state and benefits the state’s economy positively. An IRP that accomplishes these objectives is best for Michigan.

Consumers’ reply brief, p. 10.

Consumers replies to Energy Michigan’s claim that the one-time solicitation might ultimately lead to PPAs with CMS Enterprises. *Id.* Consumers responds that “[t]he Company has not yet issued the solicitation, thus Energy Michigan is merely speculating which resources will win.” *Id.* Consumers avers that “even in the scenario that Energy Michigan envisions, no adverse impact on resource reliability or adequacy would result.” *Id.*

Consumers refutes Energy Michigan’s claim “that it was never invited to a settlement meeting, that its comments on the draft settlement agreement were neither welcomed nor considered,” and that Energy Michigan was explicitly told that no changes it sent the company would be considered. *Id.*, p. 11. Consumers posits that “[a] settlement meeting was held with all parties on February 16, 2022, and Energy Michigan’s counsel participated in that meeting. Energy Michigan did not engage in settlement discussions after that meeting, even though such engagement was encouraged by the Company.” *Id.* Further, Consumers states that “[b]eyond the February 16, 2022 settlement meeting, Energy Michigan was also engaged by the Company

regarding settlement on numerous occasions including March 28, 2022, April 15, 2022, and April 19, 2022.” *Id.*, pp. 11-12.

Consumers avers that “Energy Michigan’s assertions regarding the settlement process is irrelevant and beyond the scope of this case” as “other potential settlement outcomes are not within the scope of issues to be decided by the Commission in a contested settlement proceeding” *Id.*, p. 12 (citing June 7, 2019 order in Case No. U-20165). Consumers also posits that the “[Commission]’s Rules of Practice and Procedure make clear that reaching a total consensus is not required for settlement.” Consumers’ reply brief, p. 12. Consumers adds that “Rule 431 makes clear that a settlement may be ‘proposed by some of the parties.’” *Id.* (quoting Mich Admin Code, R 792.10431(3)). Further, Consumers quotes Rule 431 as stating that “‘provisions of these rules shall not be construed in any way to prohibit settlements.’” Consumers’ reply brief, pp. 12-13 (quoting Mich Admin Code, R 792.10431(3)).

Turning to the claims of the BMPs, Consumers argues that “even though the BMPs are claiming that the Settlement Agreement is flawed, they are at the same time conceding that all of those purported flaws melt away if the BMPs just get what they want—to amend the Settlement Agreement to force Consumers Energy to extend PPAs with its member plants.” Consumers’ reply brief, p. 14. Consumers posits that “[t]he BMPs’ position illuminates the fact that there are not really flaws in the Settlement Agreement, as the BMPs’ [sic] claim, and that the BMPs’ position merely seeks to promote their own economic interests.” *Id.* Further, Consumers avers that the BMPs have not established that their member plants are an economic and reasonable option for Consumers’ customers following the expiration of the current PPAs for those plants. *Id.* Consumers further reiterates its positions from brief that the company does not have an obligation to enter into new contracts with the BMPs, that the BMPs were considered in the development of

the IRP, and that the BMPs have not produced evidence that they represent a viable economic option. *Id.* Consumers asserts that the BMPs’ alternative proposal under Section 6t(6) of Act 341 is not supported because “the BMPs have failed to address and meet the filing requirements for an alternative proposal, as provided in the Certificate of Necessity and Integrated Resource Plan Alternative Filing Requirements.” Consumers’ reply brief, p. 15 (citing December 20, 2017 order in Case No. U-18461, Exhibit B). Consumers opines that the BMPs requested relief should be rejected because “[t]he BMPs have not established that their member plants will be an economic and reasonable resource option for customers and therefore, there is no basis to support the BMPs’ request to force the Company to extend PPAs with those plants.” Consumers’ reply brief, p. 16.

In response to the BMPs’ claims that the settlement agreement fails to meet the resource adequacy and reliability requirements of Sections 6t(8)(a)(i) and (iv) of Act 341, Consumers asserts that “[t]he Settlement Agreement ensures resource adequacy and capacity that is sufficient in quantity to serve anticipated peak electric load plus applicable PRMR and Local Clearing Requirement” Consumers’ reply brief, p. 17. Consumers argues that the settlement agreement has “maintained a balance of resource additions and retirements—backfilling capacity lost to accelerated retirement with the addition of new baseload resources, expansion of demand-response resources, expansion of renewable resources, and deployment of battery storage resources.” *Id.* (citing 10 Tr 4121). Consumers also reiterated that the settlement agreement provides mechanisms to procure additional capacity if needed. Consumers’ reply brief, p. 17. Consumers posits that the settlement agreement provides for “electric reliability assurance” and that the “flexibility of phased-in modular resources provided for in the Settlement Agreement PCA also provides the Company adequate time to mitigate cost, assess reliability within the reconfigured portfolio, and to modify as necessary.” *Id.*, p. 18.

Consumers contests the BMPs' claim that the company used an incorrect capacity accreditation for its solar resources. Consumers restates that the company's PCA "uses the current MISO solar capacity accreditation practices which provide solar with a 50% capacity accreditation." *Id.* (citing 10 Tr 4142). Consumers reiterates its arguments that "that MISO solar capacity accreditation value is also only relevant to newly installed solar and not solar that is in actual operation. Capacity accreditation at the Company's existing solar facilities has been as high as 65%, based on actual performance." Consumers' reply brief, p. 19 (citing 10 Tr 4142). Consumers argues that the company has supported its modeled capacity factor for solar with projections from third-party resources. Consumers' reply brief, p. 19. Thus, Consumers opines that the BMPs' resource adequacy and reliability arguments should be rejected. *Id.*

Responding to the BMPs' claims that the settlement agreement fails to meet the requirements of Section 6t(8)(b) of Act 341 and Governor Gretchen Whitmer's MI Healthy Climate Plan pursuant to ED 2020-10, Consumers argues that "the record establishes that the Settlement Agreement is aligned with that plan, and will help promote its success." Consumers' reply brief, p. 20. Consumers adds that to the extent the BMPs are arguing that additional imports from the market violate ED 2020-10, the PCA, as modified by the settlement agreement, "reduced the need for market purchases" and "continues to maintain that reduced market dependence through the purchase of the Covert Plant and one-time solicitation" *Id.*

Addressing the BMPs' assertion that Karn Units 3 and 4 could be designated as an SSR, Consumers reiterates that "an SSR designation would result from an electric transmission system deficiency that must be mitigated and not due to a capacity or energy shortfall." *Id.*, p. 21. Reiterating its earlier testimony, Consumers argues that the risk of an SSR designation is unsupported. *Id.*, pp. 20-21.

In response to the BMPs' assertion that the settlement agreement fails to appropriately balance the diversity of generation resources with the impacts on commodity price risk, Consumers asserts that the settlement agreement provides for a diverse portfolio of resources as outlined in its testimony. *Id.*, p. 21. Consumers posits that "[t]his resource mix represents a balanced and modular supply plan which provides flexibility to adjust to changes in fuel costs, technology cost, electric demand, or the business environment and insulates the Company and its customers from commodity price risks." *Id.* Further, Consumers asserts that this approach will "provide further opportunities for the utilization of diverse supply resources and protects against high customer rates." *Id.*

Consumers reiterates its arguments, outlined above, regarding the scope of the contested settlement agreement in response to the BMPs. *See, id.*, pp. 23-26. Consumers reasserts that the BMPs attempt to propose another version of the settlement agreement is "improper and not supported." Consumers' reply brief, p. 25. On pages 26 through 33 of its reply brief, Consumers addresses the BMPs' appeal of the ALJ's rulings.

Consumers asserts that Mackinac's objections to the settlement failed to comport with the Commission's procedural rules and should thus be disregarded. *Id.*, pp. 32-33.

Consumers requests the Commission approve the settlement agreement in its entirety without any modifications or conditions. *Id.*, p. 33.

5. Wolverine Power Supply Cooperative

WPSC argues that the settlement agreement "has neither the facts nor the law on its side and the Commission must reject it." WPSC's reply brief, p. 1. WPSC contends that the Staff has reversed its stance on the importance of resource adequacy as the Staff now contends that the settlement agreement "should be approved because Zonal resource adequacy is not Consumers'

problem to solve.” WPSC’s reply brief, p. 3 (citing Staff’s initial brief, p. 5). WPSC avers that while it is not the sole responsibility of Consumers to “ensure resource adequacy for the Zone, a significant component of the IRP framework is to ensure that a utility retiring resources does not do so in a manner that adversely impacts the Zone, which Consumers does here” and that “although Consumers may not be required to address a shortfall caused by others, it certainly must be required to address a shortfall it is creating.” *Id.* (emphasis omitted).

WPSC again avers that the settlement agreement is not supported by substantial evidence and that the company has not disputed the negative ZRC values for 2022-2023 and 2025-2026. *See, id.*, p. 4. WPSC reiterates concerns regarding the ELCC for solar assets, arguing that the 50% is not an accurate benchmark as “[i]t simply does not reflect reality, even if some are willing to pretend that it does.” *Id.* WPSC further states that it has “identified actual impediments to Consumers’ contemplated solar development and Consumers offered no explanation as to how it will overcome these hurdles, except to say there is time to address in future IRPs. [WPSC] identified the issues; Consumers identified no solutions.” *Id.*, p. 5.

Finally, WPSC argues that the Staff’s briefing lacks confidence “[m]uch like Consumers’ failure to explain its solution to the hurdles related to solar development, Staff appears to be counting on speculative ‘other resources’ that are not identified in brief or the record.” *Id.* Therefore, WPSC avers that the settlement agreement is speculative and should be denied under Rule 431(5).

6. The Biomass Merchant Plants

In reply to Consumers, the BMPs reference their initial brief to respond to the claim that the BMPs’ “requested relief is beyond the scope of these proceedings” averring that “[i]t is not.” BMPs’ reply brief, p. 2. The BMPs reiterate that while “PURPA may no longer require

Consumers to purchase generation from the Biomass Plants [that] does not mean that such purchases are not reasonable and prudent as a matter of state law” and that Consumers has done everything possible “to exclude the Biomass Plants from the IRP, regardless of whether or not including them would be reasonable and prudent.” *Id.* (citing to BMPs’ initial brief, p. 29-38). Reiterating the testimony and briefing, the BMPs state that the company never requested cost information from the BMPs and failed to explain why the cost of new construction was utilized for biomass generation. *See*, BMPs’ reply brief, pp. 2-4.

Responding to Consumers’ contention that the BMPs would be eligible to bid into the first tranche of the one-time solicitation, the BMPs aver that:

[w]hile the Biomass Plants can be dispatched within their operational limits, they cannot be dispatched within one hour if they are not running. That fact, in addition to the fact that all of the Biomass Plants’ current contracts extend into the 2025 to 2030 time period will exclude them from bidding in that solicitation.

Id., p. 4 (referencing Consumers’ initial brief, p. 45). The BMPs again reference objections and excluded evidence which they aver were inappropriately ruled upon by the ALJ. The BMPs aver that Consumers failed to discuss “whether [Consumers] is likely to sign power purchase agreements with [the CMS plants] as a result of the first tranche of the One Time Solicitation, which is probable.” *Id.*, pp. 5-6. Further, the BMPs restate record testimony to aver that Consumers has still failed to rebut the BMPs’ testimony regarding the overstated solar capacity factor the company has utilized, and the risk associated with proposed solar additions. *See, id.*, pp. 6-10. The BMPs argue that Consumers’ dismissal of the risks relating to the solar additions, and “its refusal to add the 188 MW of baseload, net zero carbon, renewable generation from the Biomass Plants to its IRP” are invalid and raise “serious questions as to whether the Biomass Plants are being excluded from the IRP for some other undisclosed commercial reason.” *Id.*, pp. 10-11.

V. Discussion

The Commission finds that the contested settlement agreement at issue in this case should be approved.

As stated above, Commission approval of a contested settlement agreement is appropriate where the Commission determines the following requirements have been met: (1) that the objecting parties have been given a reasonable opportunity to present evidence and arguments in opposition to the settlement agreement, (2) the public interest is adequately represented by the parties who entered into the settlement agreement, (3) the settlement agreement is in the public interest, (4) the settlement agreement represents a fair and reasonable resolution of the proceeding, and (5) the settlement agreement is supported by substantial evidence on the record as a whole.

Mich Admin Code, R 792.10431.

The Commission finds that all the requirements of Rule 431 have been met. The Commission has provided a reasonable opportunity to those parties that objected to the settlement agreement to present evidence and argument in opposition to the settlement agreement. The parties were given the opportunity to submit direct and rebuttal testimony, file initial and reply briefs, and appear at an evidentiary hearing regarding the contested settlement agreement before a presiding officer. As the parties to this case observed, the principal record in this case consists of 4,094 pages of transcript and over 500 exhibits admitted into evidence. The record on the contested settlement alone consists of 315 additional pages of transcript and 22 additional exhibits admitted into evidence.

With respect to the second criterion, the record shows that the signatories to the settlement agreement represent a broad cross-section of interests, including residential customers, commercial and industrial customers, businesses in Michigan's advanced energy sector, environmental groups,

a transmission company, and third-party developers. *See*, 10 Tr 4407-4408. The Commission also notes that the Court of Appeals has affirmed the Commission's determination that the public interest is adequately represented by the Staff when the Staff is party to a contested settlement agreement. *Attorney General v Mich Pub Serv Comm*, 237 Mich App 82, 93-94; 602 NW2d 225 (1999). Accordingly, the Commission finds that the public interest is adequately represented by the parties who entered into the settlement agreement.

Rule 431(5)(c) requires the Commission to make a three-part finding that: (1) the settlement agreement is in the public interest, (2) represents a fair and reasonable resolution of the proceeding, and (3) is supported by substantial evidence on the record as a whole.

The Commission finds that the settlement agreement is in the public interest. The Commission finds persuasive the testimony by Consumers and others that the settlement agreement was the result of good-faith negotiation that resulted in significant compromises for all involved. The negotiation of the parties is evident when comparing the details of Consumers' initial IRP filing with the terms of the proposed settlement agreement. Signatory parties to this case highlighted the following provisions as compromises reached by settlement that are in the public interest, represent a fair and reasonable resolution of the proceeding, and are supported by substantial evidence on the record as a whole:

- The agreement that Consumers retire Campbell Units 1, 2, and 3 in 2025, which will result in savings to ratepayers, reduce the production of environmental pollutants, such as SO₂, NO_x, and particulate matter, and advance Michigan's clean energy goals as outlined in the MI Healthy Climate Plan as well as provide additional public health benefits;

- The agreement that Consumers will purchase the Covert plant in 2023, which will add 1,114 ZRCs to MISO Zone 7 to support reliability for Consumers as well as overall resource adequacy of the Zone;
- The agreement to conduct a one-time solicitation for 200 ZRCs of capacity and associated energy and RECs, which will provide additional clean capacity resources for Consumers' portfolio;
- The agreement that Consumers will deploy the battery program outlined in the rebuttal testimony in the principal case which will formalize an important component of a cleaner energy grid while enhancing reliability and resource adequacy;
- The agreement to seek recovery of the unrecovered book value and decommissioning costs of retiring coal units through regulatory asset treatment, rather than continued recovery through traditional ratemaking, which provides the potential for customer savings;
- The agreement that Consumers will donate \$5 million dollars in shareholder funds to support bill assistance for lower-income customers along with continued annual donations;
- The agreement that Consumers will provide beneficial modeling in its next IRP, including total emissions, annual particulate matter health impacts, an environmental justice screening tool, projected low-income energy efficiency participation levels, publicly available rooftop solar adoption rates, and transmission import analysis; and
- The agreement that Consumers will take steps to engage and gather input from the public prior to the filing of its next IRP with the Commission, which will ensure that additional information and perspectives are available to inform both the company's assessment of its future resource options as well as Commission and stakeholder review of its proposals.

Energy Michigan, WPSC, the BMPs, and Mackinac disagree with the conclusion that the settlement is in the public interest and represents a reasonable resolution to the proceeding. The objecting parties' concerns involve the resource adequacy, reliability, and competitive pricing in MISO Zone 7. Specifically, the objecting parties argue that: (1) the settlement agreement does not meet the resource adequacy needs of MISO Zone 7 and (2) the one-time competitive solicitation will not adequately replace the capacity from retiring coal-fired generation. Each of these concerns are addressed in turn.

A. The Resource Adequacy of Zone 7

The parties objecting to the settlement agreement claim that the settlement agreement does not address the need for incremental capacity replacements in MISO Zone 7 following the retirement of Campbell Units 1, 2, and 3 to meet the resource adequacy requirements of the zone. As such, the objecting parties conclude that Consumers' PCA fails to meet the resource adequacy requirements of Section 6t(8)(a)(i) and (iv) that the Commission must balance "[r]esource adequacy and capacity to serve anticipated peak electric load, applicable planning reserve margin, and local clearing requirement" and "reliability" to determine that the integrated resource plan is the most reasonable and prudent means of meeting energy and capacity needs. The Commission disagrees.

The Commission finds the testimony of the Staff, MNS, and Consumers compelling. As Consumers testifies, the settlement agreement continues the annual solicitation process adopted by the company in its 2018 IRP. 10 Tr 4121. By preserving the solar ramp-up proposed in the original PCA, the settlement agreement adds 250 ZRCs of new solar generation by the 2025/2026 PY, increasing to 852 ZRCs by the 2028/2029 PY. 10 Tr 4350. The settlement agreement provides that Consumers will deploy a new utility-scale battery storage program which will add

approximately 71 ZRCs of new capacity to the zone. 10 Tr 4350. Finally, preserving the EWR and DR provisions from Consumers’ original PCA, the settlement provides 94 ZRCs of demand-side resources by the 2025/2026 PY, increasing to 2031 ZRCs by the 2028/2029 PY. The settlement also provides for increases in both the demand-side resources and solar resources in later years. 10 Tr 4350.

In addition to these new resources, the settlement agreement provides for the acquisition of the Covert plant, which will transfer approximately 1,114 ZRCs from PJM into MISO Zone 7. 10 Tr 4123, 4225, 4230, 4331. The settlement agreement has the effect of adding approximately 770 ZRCs through the continued operation of Karn Units 3 and 4 until May 31, 2031, consistent with the design lives of those units. 10 Tr 4225, 4334.

MNS provides that “the settlement [agreement] will result in a projected net increase of at least 127 ZRCs. By 2028/29, the projected net increase will be at least 923 ZRCs.” 10 Tr 4350. The Staff further contends that, “[t]he Company was originally proposing to retire approximately 2800 MW (nameplate) generation from MISO Zone 7 . . . ,” meanwhile the settlement agreement “only retires a portion of that amount, approximately 1500 MW” 10 Tr 4405. The projections by both MNS and the Staff are in addition to any resources that may be acquired through the one-time solicitation, discussed below. 10 Tr 4351-4352, 4406. As Consumers observes, the settlement agreement provides for more capacity in Zone 7 than was included in the company’s originally filed PCA. 10 Tr 4230. The Commission thus finds that the settlement agreement provides a reasonable and prudent plan for meeting resource adequacy requirements.

The Commission acknowledges the larger resource adequacy concerns of the objecting parties as valid and timely. The broader resource adequacy of Zone 7 and the MISO region has an impact on both Consumers’ customers and the state as a whole. The Commission observes that the

2022/2023 MISO PRA results indicate a capacity shortfall for the MISO North and Central Regions.⁵ These auction results indicate that many LSEs in MISO will experience a greater risk of implementing involuntary conservation measures even though many of them would appear to be resource adequate when viewed as a stand-alone entity. While the market construct within MISO allows for the pooling of resources to lower the total cost to customers, this market construct means that the planned retirements and resource decisions of one utility impact the customers of other utilities within the Zone and the greater regional transmission organization (RTO).

While the Commission agrees with Consumers' assertion that the company is not responsible for the reliability of the entirety of MISO Zone 7, it is also clear that a deficiency in any part of Zone 7 would increase the likelihood of grid outages for all customers in Zone 7, including those served by Consumers.

As noted above, however, the approval of the settlement agreement enhances zonal resource adequacy in the short, medium, and long term(s). In the short term, the acquisition of the Covert plant will transfer approximately 1,114 ZRCs from PJM into MISO, providing much needed additional capacity to LRZ 7 for the next MISO PY. In the long term, as noted by Mr. Jester, "[c]ontinuing to operate Karn 3-4 supports Consumers' attainment of planning reserve margin requirements by maintaining more than 780 ZRCs in the Company's portfolio." 10 Tr 4334. And as the Staff noted, the settlement agreement represents "a resource adequacy improvement over the Company's original PCA[.]" and provides for approximately 400 ZRCs of new resources within

⁵ The resources in the MISO region operate as a shared pool of resources to meet the PRMR. As demonstrated in the MISO 2022/2023 PRA results, capacity shortfalls in four MISO Zones resulted in the entirety of the MISO North/Central Regions having a slightly increased risk of needing to implement temporary controlled load sheds. The 2022/2023 PRA results are available at: <https://cdn.misoenergy.org/2022%20PRA%20Results624053.pdf> (accessed, June 17, 2022).

MISO Zone 7 by 2025, in addition to the one-time solicitation for 700 MW set forth in the settlement agreement. 10 Tr 4405, 4406. Finally, while acknowledging the challenges to resource adequacy that were highlighted in MISO's recent PRA results, the Commission notes Consumers' testimony that it "will file at least one, if not multiple, IRPs" between now and when any projected shortfalls are likely to occur, and that it will have "ample time to respond and adjust the PCA" if necessary. 10 Tr 4143-4144. As such, the Commission is satisfied that the approval of the settlement agreement will enhance resource adequacy in Zone 7 in both the near-term and long-term.

In order to ensure future IRPs appropriately consider zonal resource adequacy in addition to the resource requirements of a particular utility, the Commission directs the Staff to include a requirement for each utility to consider the impacts of its PCA on the resource adequacy of its own customers, the LRZ in MISO or its equivalent in PJM, and also assess the potential impacts, if any, of its decisions on customers in neighboring Zones, regions, or RTOs in the upcoming IRP filing requirements update in Case No. U-18461 in order to better enable the Commission to determine whether future PCAs meet resource adequacy needs of the LRZ.

B. The One-Time Solicitation

The parties objecting to the settlement agreement also express concerns regarding the one-time solicitation as it is outlined in the settlement agreement. Among the concerns, Energy Michigan asserts that the 500 ZRC capacity need that Consumers is seeking to fill through the first tranche of the one-time solicitation will result in capacity that is not additional to what is already being counted toward MISO Zone 7's resource adequacy requirements. 10 Tr 4297. The BMPs and WPSC express concerns that the timing and framing of the one-time solicitation will not result in new resources being added to the market. Specifically, these two parties assert that it will not

be possible for new generation to obtain a MISO Interconnection Services Agreement, complete project engineering, obtain financing, and construct a new plant by 2025, as the settlement agreement requires the generation to provide Consumers with a capacity credit in MISO Zone 7 by 2025. The Commission finds that this reasoning for denying the settlement agreement is speculative. As several parties contended, the terms of the settlement agreement require that the resources acquired be competitively sourced. The Commission finds persuasive testimony that “respondents to the solicitation could be from some of the projects currently in the MISO queue . . . that makes up nearly 1,800 MW of projects that are currently in Study Phase 2 or 3.” 10 Tr 4404 (footnote omitted). And further that “there are more than 13,011 MWs of solar, battery, and solar/battery hybrid projects located in MISO Zone 7 that have an application in-service date by or before June 1, 2025 Of these projects, 5,365 MW of solar, 499 MW of solar/battery hybrid, and 370 MW of battery have completed Phase 2 or Phase 3 interconnection studies and are therefore highly likely to proceed if the developer has an offtake or build-transfer agreement.” 10 Tr 4363-4364 (footnotes omitted). The Commission finds that the one-time solicitation is in the public interest as it is likely to contribute to—or at a minimum not be detrimental to—the overall resource adequacy of MISO Zone 7.

However, to clarify, the Commission does not interpret the language of the settlement agreement to mean that it is pre-judging any approval requests it may receive from Consumers as a result of this one-time solicitation or any other approval requests that Consumers may file following the implementation of its PCA. The language of the settlement reads:

[T]he actual selected bid(s) will be submitted in Case No. U-21090 for Commission approval subsequent to the completion of the One-Time Solicitation;

In that approval proceeding, the Commission shall: (i) confirm whether the solicitation process followed by the Company is consistent with the requirements of the Settlement Agreement; (ii) grant approval of the recovery

of the costs associated with the selected project(s) pursuant to applicable law or make a preliminary finding that the costs associated with the project(s) that prevail in the solicitation are reasonable and prudent; and (iii) grant any other approvals or findings necessary as required or provided by applicable law.

Settlement Agreement, pp. 6-7. As such, the Commission will examine the results of the one-time solicitation carefully and will scrutinize any effects it may have on resource adequacy and competitive pricing in Zone 7.

Having addressed each of the arguments as to whether the settlement agreement is in the public interest and represents a fair and reasonable resolution of the proceeding, the Commission finds that, for all the reasons set forth, the settlement agreement is in the public interest. The Commission also finds that the proposed settlement agreement is a fair and reasonable resolution of this proceeding. In addition, having read the record, the Commission likewise finds the settlement agreement to be supported by substantial evidence on the record as a whole. Moreover, as agreed to by the parties in paragraph 1 of the settlement agreement and supported by the record, the Commission finds that Consumers' PCA as amended by the settlement agreement is the most reasonable and prudent means of meeting Consumers' energy and capacity needs and otherwise meets the requirements of MCL 460.6t(8).

THEREFORE, IT IS ORDERED that:

- A. The settlement agreement, attached as Exhibit A, is approved.
- B. Unless otherwise provided in the settlement agreement, the terms of the approved settlement agreement shall take effect immediately upon issuance of this order.
- C. The Commission Staff shall include a requirement for each affected utility to consider the impacts of its proposed course of action on the resource adequacy of its own customers, the Midcontinent Independent System Operator, Inc. Local Resource Zone or respective PJM

Interconnection, L.L.C. Zone, and neighboring Zones, regions, or regional transmission organizations in the updated integrated resource plan filing requirements to be filed on June 30, 2022, in Case No. U-18461, as outlined in this order.

D. In accordance with paragraph 11(g) of the settlement agreement, Consumers Energy Company shall file, within 30 days of this order, revised Standard Offer tariff sheets and a revised Standard Offer contract, to reflect the Standard Offer construct and rates approved as part of the approved settlement agreement. Also pursuant to paragraph 11(g), parties shall have 14 calendar days subsequent to these filings to provide comments to the Commission in this docket.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, under MCL 462.26. To comply with the Michigan Rules of Court's requirement to notify the Commission of an appeal, appellants shall send required notices to both the Commission's Executive Secretary and to the Commission's Legal Counsel. Electronic notifications should be sent to the Executive Secretary at mpscedockets@michigan.gov and to the Michigan Department of the Attorney General – Public Service Division at pungpl@michigan.gov. In lieu of electronic submissions, paper copies of such notifications may be sent to the Executive Secretary and the Attorney General – Public Service Division at 7109 W. Saginaw Hwy., Lansing, MI 48917.

MICHIGAN PUBLIC SERVICE COMMISSION

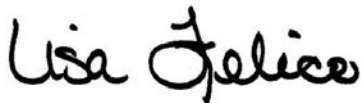


Daniel C. Scripps, Chair



Tremaine L. Phillips, Commissioner

By its action of June 23, 2022.



Lisa Felice, Executive Secretary

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of an Integrated Resource Plan	)	Case No. U-21090
under MCL 460.6t, certain accounting	)	
approvals, and for other relief.	)	
_____	)	

SETTLEMENT AGREEMENT

Pursuant to MCL 24.278 and Rule 431 of the Michigan Administrative Hearing System's Rules of Practice and Procedure before the Michigan Public Service Commission ("MPSC" or the "Commission"), the undersigned parties agree as follows:

WHEREAS, on June 30, 2021 Consumers Energy Company ("Consumers Energy" or the "Company") filed an Application requesting approval of the Company's Integrated Resource Plan ("IRP") pursuant to Section 6t of 2016 PA 341, MCL 460.6t, the Commission's June 7, 2019 Order Approving Settlement Agreement in Case No. U-20165, and all other orders and applicable law. The Company filed testimony and exhibits in support of its positions concurrently with its Application.

WHEREAS, the initial prehearing conference was held on July 22, 2021 before Administrative Law Judge ("ALJ") Sally L. Wallace. Beyond the Company, the parties to the IRP are: the MPSC Staff ("Staff"); the Attorney General; Hemlock Semiconductor Operations, LLC ("HSC"); the Biomass Merchant Plants ("BMPs")¹; Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club ("MNS"); Great Lakes Renewable Energy

¹ The BMPs consist of: Cadillac Renewable Energy, LLC, Genesee Power Partners Limited Partnership, Decker Energy-Grayling, LLC, Hillman Power Company, LLC, Tondur Corporation, National Energy of Lincoln, LLC, f/k/a Viking Energy of Lincoln, LP and National Energy of McBain, f/k/a Viking Energy of McBain, LLC.

Association (“GLREA”), Environmental Law and Policy Center, the Ecology Center, Vote Solar, and the Union of Concerned Scientists (collectively, the Clean Energy Organizations (“CEO”)); Residential Customer Group (“RCG”); Association of Businesses Advocating Tariff Equity (“ABATE”); Michigan Energy Innovation Business Council, Institute for Energy Innovation, and the Clean Grid Alliance (collectively, “Michigan EIBC/IEI/CGA”); Energy Michigan, Inc. (“Energy Michigan”); Midland Cogeneration Venture Limited Partnership (“MCV”); Michigan Electric Transmission Company, LLC (“METC”); Michigan Public Power Agency (“MPPA”); Wolverine Power Supply Cooperative (“Wolverine”); the Citizens Utility Board (“CUB”); the Mackinac Center for Public Policy (“Mackinac”); and the Urban Core Collective (“UCC”). 1 TR 11-12, 22.

WHEREAS, Consumers Energy filed testimony and exhibits requesting approval of the Company’s IRP Proposed Course of Action (“PCA”) in its entirety, as the most reasonable and prudent means of meeting the Company’s energy and capacity needs through 2040. The Company specifically requested the Commission to make the following determinations:

- (i.) Approve Consumers Energy’s PCA, which is inclusive of all proposals presented by the Company in this case, including the battery deployment program, as the most reasonable and prudent means of meeting the energy and capacity needs of the Company and its customers;
- (ii.) Approve the Company’s acquisition and proposed purchase costs for the New Covert Generating Facility (“Covert Plant”) and Dearborn Industrial Generation (“DIG Plant”), the Livingston Generating Station (“Livingston Plant”), and the Kalamazoo River Generating Station (“Kalamazoo Plant”), in the manner proposed by the Company, and proposed Energy Waste Reduction (“EWR”), Demand Response (“DR”), and Conservation Voltage Reduction (“CVR”) costs which will be commenced by the Company within three years following the Commission’s expected approval of the Company’s IRP;
- (iii.) Approval of the selection and proposed purchase of the DIG, Kalamazoo, and Livingston plants, by the Company from its affiliate, CMS Enterprises. The transaction was a result of a competitive solicitation and is compliant with the Commission’s Code of Conduct requirements. In the alternative, while complying with all other provisions of the Code of Conduct, the Company

requests a waiver of the asset transfer provision of the Code of Conduct, Mich Admin Code R 460.10108(4), for the acquisition of the DIG, Livingston, and Kalamazoo plants, from CMS Enterprises;

- (iv.) Approve the Company's proposal to recover the unrecovered book balances of D.E. Karn ("Karn") Units 3 and 4 and J.H. Campbell ("Campbell") Units 1, 2, and 3, including decommissioning costs, through regulatory asset treatment, with full return, over the design lives of those units;
- (v.) Approve the Company's proposals to: (i) defer employee retention costs related to the proposed accelerated retirements of Karn Units 3 and 4 and Campbell Units 1, 2, and 3, and (ii) defer retirement transition costs for future recovery;
- (vi.) Approve the Company's proposed modifications to its Public Utility Regulatory Policies Act of 1978 ("PURPA") construct and the Company's proposed competitive procurement process and the use of that competitive procurement process for: (i) determining PURPA avoided costs rates, and (ii) determining and addressing the Company's capacity position under PURPA;
- (vii.) Determine that the Company has no PURPA capacity need so long as the Company is implementing the PCA, with the competitive procurement process proposed by the Company; and
- (viii.) Approve the Company's proposed Financial Compensation Mechanism ("FCM") for any new, or newly amended, Power Purchase Agreements ("PPAs") entered into by the Company.

Staff and other intervening parties filed testimony and exhibits addressing various issues.

NOW THEREFORE, for purposes of settlement of Case No. U-21090, the undersigned parties agree as follows:

1. The parties agree that the Company's PCA, as modified in this Settlement Agreement, should be approved as the most reasonable and prudent means of meeting the Company's energy and capacity needs over the 5-year, 10-year, and 15-year time horizons. The parties agree that the Company will file its next IRP consistent with the requirements of MCL 460.6t.

2. The parties agree that the PCA shall include the Company's proposed purchase of the Covert Plant in 2023 but shall not include the ownership of the DIG, Kalamazoo, and

Livingston plants. The parties agree that the identified capital costs that the Company will incur for DR (\$23,751,000), CVR (\$9,736,315), and the purchase of the Covert Plant (\$815 million) in the next three years (June 2022 – June 2025) are reasonable and prudent and approved for cost recovery purposes and will be included in rates in a future Company rate case consistent with MCL 460.6t(11) and (17). The parties further agree to the approval of the projected capacity value provided by the Covert Plant and the DR (projected to achieve a total of 641 MW (657 Zonal Resource Credits (“ZRCs”)) by 2025), CVR (projected to achieve 136,351 MWh savings by 2025, 56.81 MW savings by 2025), and EWR (projected to achieve 545,305 MWh savings in 2025, 879 MW savings by 2025) resources included in the PCA during the next three years. The parties further agree that the Company shall continue to file an annual reporting template with the Commission addressing the implementation of the approved DR and CVR resources above.

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

4. The parties agree that (i) Karn Units 3 and 4 will be retired on or before May 31, 2031, absent extraordinary circumstances that require prolonged operation, such as a System Support Resource designation by Midcontinent Independent System Operator, Inc. (“MISO”) or other emergent issues within the Company’s generation portfolio which require continued

operation of Karn Units 3 and 4 to maintain sufficient supply; and (ii) Campbell Units 1, 2, and 3 will be retired on or before May 31, 2025.

5. The parties agree that the Company will not file an application for a financing order for the unrecovered book balance and decommissioning costs of Campbell Units 1, 2, and 3. The parties agree that the Commission will permit Consumers Energy to recover the unrecovered book balance of Campbell Units 1, 2, and 3 through the Company's proposed regulatory asset treatment, with a return equal to the Company's weighted average cost of capital ("WACC") premised on the return on equity approved by the Commission in rate cases prior to the retirement date of those units and a 9.0% return on equity after the retirement date of those units, as part of the Company's electric rates over the current design lives of those units. The 9.0% return on equity will be used to modify the capital structure filed with each rate case and the return on equity will be the only modification to the capital structure used to calculate the return on the regulatory asset after the retirement date of the units. The parties further agree that the Company will be permitted to record a regulatory asset for actual decommissioning spending for Campbell Units 1, 2, and 3, with a return on the regulatory asset, with subsequent rate recovery in a rate case after a review of the reasonableness and prudence of the expenses. Recovery of the associated decommissioning and ash disposal costs will be treated as follows:

- a. The decommissioning costs, less salvage value, related to Campbell Units 1, 2, and 3 and the ash disposal costs related to Campbell Units 1, 2, and 3 will be recorded, as spent, to a regulatory asset; and
- b. The Company may request recovery in future base rate proceedings, and upon Commission determination that the Company has incurred those costs as the result of reasonable and prudent actions, they shall be included in rates. The Company will ensure that the amounts recovered through a regulatory asset account are net of any accumulated depreciation amounts.

6. The parties agree that subsequent to the Commission's order approving this Settlement Agreement, the Company shall issue a competitive solicitation ("the One-Time Solicitation") which will include the following parameters:

- a. The One-Time Solicitation will seek projects which will provide the Company with capacity credit in the MISO Zone 7 starting in the 2025 Planning Year;
- b. The One-Time Solicitation will include two all source tranches:
 - i. The first tranche will seek up to 500 ZRCs of capacity and associated energy and renewable energy credits ("RECs"), if applicable, from PPAs with terms up to 10 years. This tranche will seek dispatchable, non-intermittent generation capable of dispatching up or down in every hour of the year in response to wholesale energy market signals, providing capacity which meets the Local Clearing Requirement of MISO Zone 7; and
 - ii. The second tranche will seek up to 200 ZRCs of capacity and associated energy and RECs, if applicable, secured from unaffiliated third parties via PPAs or other third-party agreements that do not result in Company ownership with terms up to 25 years, at the discretion of the bidder. This tranche will seek intermittent resources and dispatchable, non-intermittent clean capacity resources (including battery storage resources), providing capacity which meets the Local Clearing Requirement of MISO Zone 7. This tranche will furthermore take into consideration the ability of the offered capacity to meet the Local Clearing Requirement of MISO Zone 7 for the duration of the contract length. Prior to the issuance of the second tranche portion of the One-Time Solicitation, the Company shall hold a stakeholder meeting including parties to this case and energy storage developers to discuss methods to improve RFPs and response to solicitations with respect to stand-alone storage projects and hybrid-storage projects.
- c. The Company's acquisition of the 700 ZRCs and associated energy and RECs, if applicable, sought in the One-Time Solicitation shall be considered incorporated into the PCA approved in Paragraph 1 of this Settlement Agreement. However, the actual selected bid(s) will be submitted in Case No. U-21090 for Commission approval subsequent to the completion of the One-Time Solicitation;
 - i. In that approval proceeding, the Commission shall: (i) confirm whether the solicitation process followed by the Company is consistent with the requirements of the Settlement Agreement; (ii) grant approval of the recovery of the costs associated with the selected project(s) pursuant to applicable law or make a preliminary finding that the costs associated

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

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

7. The parties agree to the approval of the Company's proposed accounting request to defer expense related to the Campbell site severance and retention agreement, utilizing a regulatory asset to record the deferred amounts. The deferred amounts for 2022 will be capped at \$26 million. All amounts deferred for 2022 and beyond will be reviewed in future rate cases. This Settlement Agreement does not permit the Company to defer amounts related to the Campbell site severance and retention agreement outside of 2022.

- a. Consumers Energy will publicly file in Case No. U-21090 its community transition plan for Karn Units 1 through 4 within 150 days of all four Karn Units ceasing operation; and
- b. Consumers Energy will develop a draft community transition plan for the Campbell site. During the development of this draft community transition plan for the Campbell site, Consumers Energy will consult with community-based organizations and community members living in the area surrounding the retired assets on the community transition plan before finalizing and filing it for informational purposes in Case No. U-21090.

8. The parties agree to the extension of the annual competitive bidding process used to acquire the supply-side resource technologies specified in the PCA, as approved in Case No. U-20165 (collectively the "Annual Solicitations" and individually an "Annual Solicitation"), with certain modifications included below:

- a. Qualifying Facilities ("QFs") that the Company has a legal obligation to purchase from under PURPA (such facilities are referred to as "QFs" in this Settlement Agreement), may bid any technology into the Annual Solicitation but will be required to submit an offer consistent with the PPA terms sought in the Annual Solicitation;
- b. The competitive bid process shall be administered by an independent third party. The evaluation criteria and process is to be made available to all bidders submitting responses for the specific technology requested by the

Company, as part of the RFP, to ensure transparency. QFs may bid any technology that meets the requirements of PURPA. A ranking of proposals is to be used by the independent third party and provided to the Company for selection;

- c. In its September 9, 2021 Order in Case No. U-20852 the Commission adopted competitive bidding guidelines titled “Competitive Procurement Guidelines for Rate-Regulated Electric Utilities (Not for PUPRA Compliance) and “Competitive Procurement Guidelines For Rate-Regulated Electric Utilities for PURPA Avoided Cost and Capacity Determination.” The “Objective” of the adopted guidelines provides that when the guidelines are utilized by utilities, it is presumed that resulting projects and contracts are reasonable and prudent and in the event utilities diverge from the guidance provided in the guidelines, it is expected that the utility will provide sufficient justification in order to receive Commission approval and recovery. In the Annual Solicitation process, the Company will follow the Commission’s adopted guidelines, including the ability to diverge from the guidance as provided in the guidelines;
- d. The first competitive solicitation for the Company pursuant to this Settlement Agreement will be conducted no later than December 31, 2022. New full avoided cost rates stemming from each competitive solicitation will be filed with the Commission for review and approval within 30 days of the conclusion of each competitive solicitation;
- e. The Company will seek term lengths for competitively bid projects up to 25 years, at the discretion of the bidder;
- f. The Company will seek to acquire the target amount of capacity identified in the PCA for each Annual Solicitation period and may exceed that target amount depending on the amount of bids, the size of projects bid, cost and value, and variations in project commercial operation dates. Total newly acquired capacity will be reconciled against the amount of capacity projected in the PCA in the Company’s next IRP. (For example, if the Company acquired more capacity than planned, the proposed resource plan in the next IRP would incorporate that additional capacity with a potential reduction in the capacity needed going forward.);
- g. If the Company is unable to meet the target capacity amount identified in the PCA in any given Annual Solicitation, the remaining "open" capacity will not be offered to QFs. The remaining capacity would instead be addressed through the process described in Paragraph 8.f.;
- h. The parties agree and acknowledge that there are supply chain, energy security, labor, and environmental benefits associated with robust, local clean energy manufacturing capabilities. As part of the Company’s competitive bidding process, the parties agree that the Company will, to the extent

reasonably possible, incorporate clear, fair, and transparent criteria in the bid evaluation process to recognize value associated with clean energy supply chain diversification and sustainability, including intended use of Michigan manufactured components and low-carbon manufacturing as verifiable by life cycle assessment and/or disclosure using public, third-party verified environmental product declarations. The Company agrees to consult with parties to the settlement on the details of such bid evaluation criteria. Nothing in this settlement alters the opportunity for stakeholders and potential bidders to review and comment on any new proposed bidding criteria through the process as set forth in the MPSC's competitive bidding guidelines approved in MPSC Case No. U-20852 on September 9, 2021;

- i. The parties agree that the Annual Solicitation process does not restrict the Company's ability to make short-term capacity additions to address capacity shortfalls which cannot reasonably be addressed through the Annual Solicitation process; and
- j. The Company may pursue supply-side resource pilots for new and emerging technologies outside of an Annual Solicitation subject to cost and project approval in its future rate cases.

9. The parties agree that the new capacity that the Company intends to procure through the PCA, in each Annual Solicitation, shall be: (i) acquired through a competitive bidding process; and (ii) approximately 50% will be from PPAs and other third-party agreements that do not result in Company ownership and approximately 50% will be owned by the Company, as acquired through a competitive bidding process. The new capacity acquired from PPAs or other third-party agreements that do not result in Company ownership will not compete against the new capacity which will be owned by the Company. The Company will use commercially reasonable efforts to maintain the 50%/50% proportion for new IRP resources from 2022 through the Company's next IRP proceeding, and in no event shall any given annual solicitation result in the Company owning more than 60% of the new capacity acquired in such solicitation. The Company, in its sole discretion, may also choose to acquire more than 50% of its new capacity from third parties. The parties further agree that the Company's affiliates will

be prohibited from bidding on the portion of the Company's new capacity acquired from third parties.

10. The parties agree to the approval of the extension of the Company's FCM approved in Case No. U-20165 equal to the product of: (i) the annual PPA payment, and (ii) the Company's after-tax WACC based on its total capital structure, which is currently 5.62%, as updated from time to time by the MPSC in electric rate case final orders. The FCM will be applicable to all new PPAs, but will not apply to PPA amendments, PURPA PPAs, and Voluntary Green Pricing PPAs. The Company shall also not receive an FCM on any PPAs executed under the Company's Renewable Energy Plan. The FCM will be subject to the cap, as provided in Attachment A of the Settlement Agreement. The parties agree that nothing in this Settlement Agreement is intended to waive the requirements of MCL 460.6t(15).

11. The parties agree to the extension of the Company's PURPA avoided cost construct, as approved in Case No. U-20165 (based on the Company's Annual Solicitations), with certain modifications included below:

- a. The Company's PURPA avoided cost construct will be subject to review in the Company's future IRP filings, as opposed to separate biennial filings;
- b. QFs 150 kWac and below are eligible to receive full avoided cost rates regardless of the Company's capacity needs;
- c. Within 180 days subsequent to the Commission's approval of this Settlement Agreement, the Company shall initiate stakeholder outreach to develop a simplified agreement, tariff-based program, or other mechanism which will allow QFs 150 kWac and below to receive full avoided cost rates. Subsequent to the completion of the stakeholder outreach, at the earliest practicable date, the Company will file a proposal with the Commission for approval;
- d. When the Company does not have a PURPA capacity need, QFs above 150 kWac, that the Company has a legal obligation to purchase from under PURPA, are eligible to receive the Company's energy-only avoided cost rates. The Company's energy-only avoided cost rates shall be based on a forecast of LMPs for the first 5 years and actual LMPs for years 6 through 10. The

Company's energy-only avoided cost rates shall not include a payment for capacity;

- e. Current existing QFs, at or below the Company's PURPA must-purchase obligation MW threshold, with a PURPA-based PPA with the Company as of January 1, 2019 shall receive new PPAs, regardless of the Company's capacity need, upon the expiration of their current PPAs based on the Company's full avoided cost rates at the time of PPA expiration. QFs that entered a PPA with the Company prior to January 1, 2019 at an amount less than full avoided cost rates, such as reduced avoided cost rates based on the Planning Resource Auction ("PRA") rate and forecasted or actual LMPs and energy-only rates which only include an energy rate and do not provide a payment for capacity, shall not automatically receive a new PPA at the full avoided cost rate when their current PPA expires. QFs that have entered a PPA with the Company after January 1, 2019 are not eligible to receive a new full avoided cost rate PPA with the Company regardless of the Company's capacity need;
- f. QFs that the Company has a legal obligation to purchase from under PURPA, and which are eligible for full avoided cost rates, may select PPA terms up to 20 years; and
- g. QFs up to 5 MWac, that the Company has a legal obligation to purchase from under PURPA, are eligible for the Company's PURPA Standard Offer Tariff and Standard Offer Contract. The terms of the Standard Offer Contract will also be updated from using the MISO methodology for capacity accreditation at the time of PPA execution, to the average of the MISO methodologies at the time of PPA execution and delivery under the PPA. Within 30 days following the Commission's approval of this Settlement Agreement, the Company shall file revised Standard Offer tariff sheets and a revised Standard Offer contract, to reflect the Standard Offer construct and rates approved as part of this Settlement Agreement. Parties shall be given 14 calendar days subsequent to the Company's filing to provide comments to the Commission.

12. The Company has no PURPA capacity need so long as the Company is implementing the Commission-approved PCA, as provided in Paragraph 1, including the competitive Annual Solicitation process for future capacity needs.

13. The parties agree that the Company will donate \$5 million in 2022 to a low-income fund that provides bill assistance to Consumers Energy's electric customers. The Company will also donate \$2 million annually to the same low-income fund each year during the amortization period for the regulatory asset, provided in Paragraph 5 of this Settlement

Agreement, with each annual donation contingent on the Company filing and the Commission approving a Voluntary Revenue Refund (“VRR”). The donations described in this paragraph will not be recovered in rates and Consumers Energy will consult with the Attorney General and Staff on the low-income fund receiving the donations. The Company will provide an annual report to the Commission each year a donation is made. If known, the report will include the number of households served, the number of households over 150% of the federal poverty level (“FPL”), and number under 150% of the FPL. For those households 150% of FPL and under, the report will explain, if known, whether they are receiving the funds because they exhausted other benefits such as the Michigan Energy Assistance Program or State Emergency Relief.

14. In future IRPs, beginning with its next IRP, the Company will (i) collect the necessary data to compute marginal line losses and report these with average line losses and (ii) include marginal line losses and avoided transmission and distribution costs in its evaluation of all distributed resources, including residential DR potential.

15. Consumers Energy agrees to develop a distributed generation as a resource model approach that considers economic distribution connected solar to be modeled by bundling resources installed at the customer level to compare the total economic costs to the utility of distributed generation as a resource to other selectable supply-side resources, consistent with the methodology used for EWR. The Company will develop a model that accounts for all utility costs and/or incentives associated with participating and non-participating distributed generation customers. The Company agrees to present the model approach for stakeholder review and feedback prior to the next IRP. The model approach, including any incorporated stakeholder feedback, will be included into the Company’s next IRP.

16. The parties agree that Consumers Energy's IRP set forth a proposal to be Carbon Neutral by 2040 and retire all coal generation by 2025, 14 years ahead of the original timeline. These retirements include two substantial coal and gas units totaling approximately 2,000 MW. To replace the capacity, Consumers Energy has proposed adding existing natural gas-fired generation and plans to add about 8,000 MW of solar generation by 2040, to dramatically reduce the use of fossil fuel resources. The next IRP should consider transmission and how it can facilitate the mitigation of reliability and economic impacts to the electric system. The parties also agree that strategic investment in electric transmission needs continual assessment to understand the role of transmission in allowing for the most economic path to meeting the state's energy goals while complementing Michigan's Load Serving Entities' ("LSE") objectives. Michigan is transitioning its generation portfolio and must take the appropriate steps to increase system reliability, resiliency, flexibility, and affordability. Michigan will be better positioned by taking a forward-looking approach regarding resource adequacy. The state should continue to recognize and support the value of a multitude of resources such as Solar, Wind, DR, and Distributed Energy Resources which assist in an "all of the above" approach. Transmission is essential in delivering the reliability of these resources. The value of transmission can be even further realized by leveraging those transmission resources to better assist the Consumers Energy IRP. This will allow MISO LRZ 7 to access broader pools of generation resources, be better situated for future demands placed on the system, mitigate unnecessary risks, and increase performance of those "all of the above" resources to serve the demands of Michigan's customers reliably and economically.

17. The parties agree that the Company will include the following analysis in its next IRP:

- a. The Company will provide total emissions, in lbs or tons, and rate of emissions, in lbs or tons per MWh and per MMBtu, for each owned power plant unit, or units that the Company has a power purchase agreement with, for the last 5 years of operation (for existing units) and projected for the next 5 years (for all units) for the following pollutants: carbon dioxide, nitrogen oxides, sulfur dioxide, volatile organic compounds (“VOCs”), and primary particulate matter (“PM2.5”);
- b. The Company will calculate the annual PM2.5-related health impacts associated with each power plant’s emissions. The modeling will include the impacts from primary PM2.5 emissions and PM2.5 precursors emissions (nitrogen oxides, sulfur dioxide, VOCs). The Company will use one model to evaluate the number and economic value of PM2.5-related health impacts of these emissions. The Company may use COBRA or BenMAP (which will require pollutant change inputs from another model such as InMAP) for these calculations, or models that are of equal or greater complexity and accuracy. The Company will report the total number and economic value of PM2.5-related health impacts across the US for the chosen model and spatially by Michigan county or at a higher resolution;
- c. The Company will use the MiEJScreen mapping and screening tool, or, if the MiEJScreen tool is not yet finalized, the EPA Environmental Justice Screening and Mapping Tool (“EJSCREEN”), to assess populations in a 1-mile and 3-mile buffer around each power plant location, including reporting total populations and any indicators and total index results above the 75th percentile;
- d. The Company will report projected low-income energy efficiency participation levels, low-income load-reduction data, and publicly available rooftop solar adoption rates. If available, information on rooftop solar adoption by low-income customers will be provided;
- e. The Company will include a narrative discussion of how the data obtained in a-d were considered by the utility; and
- f. To the extent that the Commission formally adopts revised Integrated Resource Plan Filing Requirements and/or revised Michigan Integrated Resource Planning Parameters that address environmental emissions, health impacts from emissions, or environmental justice, such filing requirements will supersede the terms of this Paragraph 17.

18. The parties agree that the Company will take the following steps to engage and gather input from the public prior to the filing of its next IRP with the Commission:

- a. Host meetings about the topic of the filing at a variety of times, during the daytime and the evening, with the Company providing equivalent content and equivalent and sufficient time for robust public response at each session;
- b. Host meetings about the topics in the filing with a roughly equal mix between (i) in-person meetings and (ii) virtual or hybrid meetings;
- c. For the duration of the proceedings before the MPSC, make available on its website recordings of (i) all virtual or hybrid meetings and (ii) to the extent feasible, any portion of an in-person meeting in which the Company is (a) addressing all participants in the meeting and/or (b) receiving public feedback and/or questions in a format intended to be heard by all participants in the meeting at the same time;
- d. When requested 10 business days prior to a meeting, provide translations of materials for the benefit of those communities whose first language is not English, based on the demographics of the community;
- e. When requested within 30 days subsequent to a meeting, the Company will use best efforts to provide a translation of recordings of the community meeting in a language specified by the person requesting the translation. Such translation recordings will be provided within 15 business days, subject to the Company's best efforts, after the request is received. If the Company is unable, after a good faith effort, to find or reasonably engage the services of a translator capable of translating the recording into the language requested, the Company will not be obligated to provide the translation;
- f. When requested at least 10 business days prior to an in-person meeting, the Company will use best efforts to include at least one live interpreter who can translate in the requested language. If the Company is unable, after a good faith effort, to find or reasonably engage the services of a translator capable of translating the meeting into the language requested, the Company will not be obligated to provide the translation;
- g. Coordinate with community-based organizations when organizing and promoting meetings about the filing. The Company will solicit input regarding the time, place, and manner of the meetings from the community organizations, in addition to any other meetings the Company wishes to hold of its own accord;
- h. Use best efforts to present the details of the integrated resource planning process in accessible, non-technical language that includes, but is not limited to, descriptions of the impacts of the Company's plans on communities, the environment, and public health;
- i. Include in its filings a concise general statement of the basis and purpose of the comments received by the Company and how the Company considered,

addressed, or rejected the issues raised in those comments in the IRP (as practicable); and

- j. Subsequent to the issuance of the Commission's order approving this Settlement Agreement, the Company agrees to meet with UCC to discuss potential stakeholder outreach prior to or subsequent to future electric rate case filings.

19. The parties agree that the Company will do the following with respect to combined heat and power ("CHP") resources:

- a. Within 180 days of the effective date of the Commission's order approving the settlement, the Company will initiate a voluntary survey among its commercial and industrial customers to gauge interest in CHP (the "CHP survey"), with survey responses intended to be used by the Company to support the evaluation of: (1) the types of CHP that customers prefer, with regard to size, technology and overall configuration, on both the demand side and supply side, including co-ownership arrangements and other potential partnerships with the Company, and: (2) non-confidential information regarding locations within the Consumers Energy territory that may be most appropriate for deployment of CHP. The CHP survey will be conditioned on respondent approval of the public release of all information provided by the respondent in response to the survey. Nothing in this section is intended to require the public release of any confidential and/or commercially sensitive customer or Company information;
- b. Within 360 days of the effective date of the Commission's order approving the settlement, the Company will share the results of the CHP survey in the Case No. U-21090 e-docket, including a summary of the types of CHP that customers prefer, with regard to size, technology, and overall configuration, on both the demand side and supply side, including co-ownership arrangements and other potential partnerships with the Company; and a summary of non-confidential information regarding locations within the Company's territory that may be most appropriate for deployment of CHP, according to the CHP survey results;
- c. In its next IRP proceeding, the Company will model behind-the-meter CHP representative of a demand-side resource based upon the results from the CHP survey as appropriate; and
- d. In its next IRP proceeding, the Company will model front-of-the-meter CHP configurations based upon the results from the CHP survey as appropriate.

20. This settlement is entered into for the sole and express purpose of reaching a compromise among the parties. All offers of settlement and discussions relating to this settlement are, and shall be considered, privileged under MRE 408. If the Commission approves this Settlement Agreement without modification, neither the parties to this Settlement Agreement nor the Commission shall make any reference to, or use, this Settlement Agreement or the order approving it, as a reason, authority, rationale, or example for taking any action or position or making any subsequent decision in any other case or proceeding; provided, however, such references may be made to enforce or implement the provisions of this Settlement Agreement and the order approving it.

21. This Settlement Agreement is based on the facts and circumstances of this case and is intended for the final disposition of Case No. U-21090. So long as the Commission approves this Settlement Agreement without any modification, the parties agree not to appeal, challenge, or otherwise contest the Commission order approving this Settlement Agreement. Except as otherwise set forth herein, the parties agree and understand that this Settlement Agreement does not limit any party's right to take new and/or different positions on similar issues in other administrative proceedings, or appeals related thereto.

22. This Settlement Agreement is not severable. Each provision of the Settlement Agreement is dependent upon all other provisions of this Settlement Agreement. Failure to comply with any provision of this Settlement Agreement constitutes failure to comply with the entire Settlement Agreement. If the Commission rejects or modifies this Settlement Agreement or any provision of the Settlement Agreement, this Settlement Agreement shall be deemed to be withdrawn, shall not constitute any part of the record in this proceeding or be used for any other purpose, and shall be without prejudice to the pre-negotiation positions of the parties.

23. The parties agree that approval of this Settlement Agreement by the Commission would be reasonable and in the public interest.

24. The parties agree to waive Section 81 of the Administrative Procedures Act of 1969 (MCL 24.281), as it applies to the issues resolved in this Settlement Agreement, if the Commission approves this Settlement Agreement without modification.

WHEREFORE, the undersigned parties respectfully request the Commission to approve this Settlement Agreement on an expeditious basis and to make it effective in accordance with its terms by final order.

MICHIGAN PUBLIC SERVICE COMMISSION STAFF

By: Spencer Sattler
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Date: 2022.04.19 14:00:30 -04'00'

Date: April 19, 2022

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CITIZENS UTILITY BOARD OF MICHIGAN



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

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URBAN CORE COLLECTIVE



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19-April-2022

Date:

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The following parties do not wish to be signatories to this Settlement Agreement; however they have agreed to sign below to indicate non-objection to the Settlement Agreement.

MICHIGAN PUBLIC POWER AGENCY

By: Nolan J. Moody Digitally signed by Nolan J. Moody
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MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP

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Date: April 20, 2022

ATTACHMENT A

ATTACHMENT A

Contract Year	Total Rate (\$/MWh)
2019	\$ 55.54
2020	\$ 57.49
2021	\$ 59.38
2022	\$ 61.28
2023	\$ 63.25
2024	\$ 65.24
2025	\$ 67.24
2026	\$ 69.24
2027	\$ 71.23
2028	\$ 73.18
2029	\$ 75.08
2030	\$ 76.95

PROOF OF SERVICE

STATE OF MICHIGAN)

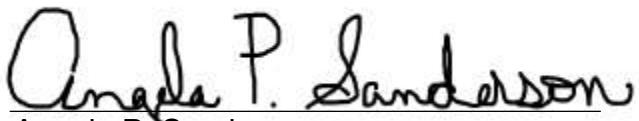
Case No. U-21090

County of Ingham)

Brianna Brown being duly sworn, deposes and says that on June 23, 2022 A.D. she electronically notified the attached list of this **Commission Order via e-mail transmission**, to the persons as shown on the attached service list (Listserv Distribution List).


Brianna Brown

Subscribed and sworn to before me
this 23rd day of June 2022.



Angela P. Sanderson
Notary Public, Shiawassee County, Michigan
As acting in Eaton County
My Commission Expires: May 21, 2024

Service List for Case: U-21090

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Attachment GG

DOE, Air Quality and Environmental Justice
Memorandum (2021)



Department of Energy
Washington, DC 20585

October 1, 2021

Enclosed is the final special environmental analysis (DOE/SEA-05) prepared by ICF, Incorporated (ICF) under direction of the Department of Energy (DOE) pursuant to the National Environmental Policy Act of 1969 (NEPA), 42 U.S.C. 4331 et seq., and DOE's implementing regulations, 10 CFR 1021.343(a).

On February 14, 2021, DOE issued an emergency order pursuant to section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the DOE Organization Act, 42 U.S.C. § 7151(b), DOE Order No. 2020-21-1, to the Electric Reliability Council of Texas (ERCOT) authorizing specific electric generating units located within the ERCOT area to operate at their maximum generation output levels under limited circumstances due to extreme weather conditions and to preserve the reliability of bulk electric power system (Order).

DOE issued the Order after determining that the emergency situation underlying ERCOT's request demanded immediate action consistent with DOE's NEPA regulations (10 CFR 1021.343(a)). As described in DOE's notice of emergency action (86 FR 18046; April 7, 2021), DOE reviewed the final data report received from ERCOT on March 31, 2021, and determined that a special environmental analysis would be the appropriate level of NEPA review. DOE has prepared special environmental analyses in other emergency situations that required immediate action. (See <https://www.energy.gov/nepa/special-environmental-analyses>). This special environmental analysis examines potential impacts resulting from issuance of the Order on air quality and environmental justice. DOE has independently reviewed the analysis provided by ICF and agrees with its conclusions. No further analysis will be conducted.

U.S. Department of Energy, Office of Electricity

Air Quality and Environmental Justice Analysis Memorandum,

July 21, 2021

Introduction

During 5 days in February 2021 (February 15–19), the Electric Reliability Council of Texas (ERCOT) requested the Department of Energy (DOE) to authorize the emergency use of power generation under Section 202(c) of the Federal Power Act. This resulted in air emissions at times exceeding their permitted emissions levels for 28 power units located in East Texas, with most power units (20) located in Harris County. At the request of the DOE Office of Electricity (OE), ICF has examined whether these additional emissions from these power units covered by the Section 202(c) authorization may have led to an exceedance of the National Ambient Air Quality Standards (NAAQS). Further, ICF conducted an environmental justice analysis of the communities potentially affected by any additional emissions during this 5-day period.

We determined at the outset that for one power unit, ERCOT was unable to obtain any information on its air emissions. Therefore, our analyses included 27 units. Although the ERCOT Section 202(c) permit covered 27 power units, only 14 of the 27 power units were at unique locations.

1 Air Quality Analysis Approach

To assess whether emissions from the power units could potentially contribute to a NAAQS violation, ICF gathered the air quality monitoring data for stations in East Texas. The Texas Commission on Environmental Quality (TCEQ) maintains an extensive network of air monitoring stations throughout the state.¹ This hourly air monitoring and meteorological data, resultant wind speed and direction, outdoor temperature, standard deviation in wind direction, and solar radiation were downloaded from TCEQ. In addition, ERCOT provided the locations for each power generating unit. Using this collected data, ICF determined if any exceedances occurred during the emergency period (February 15–19, 2021) for air pollutants having short-term ambient air quality standards. This included 1- and 8-hour CO, 1-hour NO₂, 1-hour SO₂, and 24-hour PM² standards. No assessment was made for mercury or CO₂ emissions.

ERCOT provided DOE with hourly air emission rates for each unit above its permitted levels, along with the location of each power unit. This information was used to pair air quality monitoring stations with power units. We examined pairings using proximate radial distances of 10 km and 15 km. To determine if an air monitoring station was downwind of the power unit, we used each hour's wind direction to determine if the air monitoring station aligned in a downwind direction within a ± 20 -degree window.

To further strengthen conclusions, we compared the 5-day average temperature with historical average February temperatures using climatological data from Houston International Airport as an overall representative site. Lower than average temperatures are favorable for increased

¹ https://www.tceq.texas.gov/cgi-bin/compliance/monops/select_month.pl

² Although PM₁₀ is the reported emission rate, we used the PM_{2.5} standard, as nearly all (>97 percent by mass) of the power plant emissions have a mean mass diameter of less than 2.5 microns.

buoyancy from the exhaust stack, which means the plume will rise higher, favoring lower ground-level air concentrations. A similar analysis was performed for wind speeds but using the Houston Aldine site (EPA AIRS ID 48_201_0024). Here, higher wind speeds led to increased ventilation, which decreases residence time of air pollutants, leading to lower air pollutant concentrations.

Lastly, we discuss the concept of mixing height. The *mixing height* (or depth) is defined as the height above the Earth's surface through which vertical mixing occurs. The concept of a mixing layer is well-founded on theoretical principles. The mixing height acts as a lid on air pollutants, tending to prevent further vertical mixing of emissions higher into the atmosphere. Thus, we calculated the mixing heights during the 5-day emergency period and compared them to the average February mixing heights based on the Holzworth method (U.S. Environmental Protection Agency, 1972). Mixing heights can be determined from twice daily upper-air soundings performed at 6 a.m. and 6 p.m. The nearest upper-air station to Harris County is Lake Charles, Louisiana.

Review of ERCOT Emission Rates Against Total Emissions Rates During the Emergency Use Period

We reviewed the hourly emission rate data provided by ERCOT for each power unit. The dataset is intended to report the incremental emissions for each hour that exceeded the power units' maximum permitted emission rates. To compare these incremental emissions against the total emissions from each power unit, we downloaded the Continuous Emission Monitoring System (CEMS) from EPA's Air Markets Program Data (ampd.epa.gov/ampd). CEMS data reports the total emissions for each power unit on an hour-by-hour basis either as directly measured or as calculated from other measured parameters. The ERCOT data reported hourly emissions for SO₂, NO_x, CO, PM₁₀, and CO₂; however, CEMS does not report emissions for CO and PM₁₀, so the only pollutants that can be cross-referenced between the two datasets are SO₂, NO_x, and CO₂. However, SO₂ and CO₂ are rarely reported in the ERCOT-supplied data, likely because SO₂ emission rates are well below permitted levels even during the emergency period, and CO₂ emission rates are likely not specified in operating permit levels.

Because the ERCOT emission rates are in, we expected that in most cases the ERCOT incremental increase would only be a small fraction of the total CEMS rates and that the ERCOT rates could never be greater than CEMS rates because CEMS emissions are the total emissions from the power units. To see if our understanding is consistent with the reported data, we made a graphical presentation between the NO_x incremental emission rate versus the CEMS emissions rate for each hour in which ERCOT reported an emission rate over the 5-day emergency period.

1.1 Findings – Potential for NAAQS Exceedances

We discuss a series of analyses undertaken using available air quality and meteorological data to present a weight-of-evidence approach in trying to answer the principal question—*Could the power units' excess air emissions during this emergency period have caused an exceedance of the NAAQS?*

No one analysis can definitively answer this question, so we performed a series of analyses to provide a more defensible and robust conclusion and instill greater confidence in the answer.

1.1.1 Air Quality Monitoring Stations

A review of air quality monitoring stations in all air quality modeling regions in East Texas showed no violations of the NAAQS during the emergency period. However, many of the air quality monitoring stations failed to operate during the emergency period, presumably because of power outages. Tables 1a and 1b below show the daily percentage of missing air quality data during the emergency period for power units and air quality stations that we could pair using a 10-m radius. Only 14 of the 27 power units had unique locations, and of the 14 locations, only 10 had an air quality station within 10 km. The pollutant most widely monitored, as well as the pollutant most widely reported as having emissions exceeding permit levels, is NO_x. Of the 14 locations, seven had NO₂ monitors.³ However, as highlighted in light blue and indicated with an asterisk (*), about half have missing data (likely as a result of power outages), particularly on the first 3 days of the emergency period. Other air pollutants have less air monitoring coverage but also show considerable missing data, particularly during the first 3 days of the emergency period.

The power unit codes shown in the rest of this report are defined in Appendix 1.

³ Although the emitted pollutant is NO_x, the air quality standard is for NO₂. Typically, about 10 percent of the in-stack NO_x is in the form of NO₂, and the rest is emitted as NO. However, NO is converted to NO₂ in the atmosphere with a reaction rate on the order of minutes to hours, depending on available ozone and atmospheric mixing.

Table 1a. Ambient Air Quality Monitoring Stations (CO and NO₂) Within 10 km of the Power Generation Units

Power Unit Name	Pollutants of Interest Monitored				Data Coverage by Day					Data Coverage by Day				
	CO	NO ₂	PM _{2.5}	SO ₂	CO					NO ₂				
					2/15	2/16	2/17	2/18	2/19	2/15	2/16	2/17	2/18	2/19
BOSQUE_CC1														
DDPEC_CC1	X	X	X	X	100%	21%*	0%*	50%	100%	100%	21%*	75%	100%	100%
FREC_CC2				X										
TXCTY_CC1				X										
CHAMON_CTG_0101		X								75%	0%*	17%*	100%	100%
CALHOUN_UNIT1														
THW_THWGT32		X								100%	92%	38%*	100%	100%
WAP4_WAP4														
GBY_GBYGT74		X	X							100%	96%	50%	100%	100%
PHR_CLCWA_5UNITS		X								8%*	88%	42%*	100%	96%
LH_LYN_30UNITS		X								75%	0%*	17%*	100%	100%
DSN_NEWP_10UNITS														
SOE_SEWP_10UNITS	X	X	X	X	100%	21%*	0%*	50%	100%	100%	21%*	75%	100%	100%
FEGC_UNIT1				X										

See Appendix 1 for definition of the unit codes.

Table 1b. Ambient Air Quality Monitoring Stations (PM25, SO₂) Within 10 km of the Power Generation Units

Power Unit Name	Pollutants of Interest Monitored				Data Coverage by Day					Data Coverage by Day				
	CO	NO ₂	PM _{2.5}	SO ₂	PM _{2.5}					SO ₂				
					2/15	2/16	2/17	2/18	2/19	2/15	2/16	2/17	2/18	2/19
BOSQUE_CC1														
DDPEC_CC1	X	X	X	X	100%	17%*	71%	100%	83%	100%	21%*	67%	100%	100%
FREC_CC2				X						0%*	0%*	0%*	46%*	100%
TXCTY_CC1				X						100%	100%	100%	100%	100%
CHAMON_CTG_0101		X												
CALHOUN_UNIT1														
THW_THWGT32		X												
WAP4_WAP4														
GBY_GBYGT74		X	X		100%	92%	33%*	0%*	50%					
PHR_CLCWA_5UNITS		X												
LH_LYN_30UNITS		X												
DSN_NEWP_10UNITS														
SOE_SEWP_10UNITS	X	X	X	X	100%	17%*	71%	100%	83%	100%	21%*	67%	100%	100%
FEGC_UNIT1				X						0%	0%	0%	0%	25%

Increasing the search radius from 10 km to 15 km picked up two additional air quality monitoring stations; however, the influence from the power station at that distance is substantially diminished, particularly in urban environments, where other sources of emissions will affect the monitor.

Tables 2a and 2b show the three highest monitored concentrations for NO₂, PM_{2.5}, and SO₂ over the 5-day period.⁴ The only pollutant within 50 percent of the air quality standard was PM_{2.5}, although the PM_{2.5} standard is an average over 24 hours, whereas those for NO₂ and SO₂ are 1-hour standards. No exceedances of any air quality standard occurred at these stations, nor at any air quality monitoring stations in the region of study. The highest concentration, to any air quality standard, was for the 24-hour PM_{2.5} standard at 56 percent.

The highest elevated PM_{2.5} concentrations all occurred during the late evening hours (8 p.m.–11 p.m.) on February 19, 2021. Many sources contribute to PM_{2.5} pollution, including buses, trucks, cars, and off-road sources (e.g., construction equipment, portable generators). In addition, meteorology and atmospheric chemistry play a significant role in determining the air concentration. However, it is not possible from this analysis to estimate the source contribution from the power units without additional air quality modeling analysis.

Table 2a. Top 3 Highest Air Concentrations Monitored Within 10 km of the Power Generation Units

Power Unit	NO ₂ (ppb)			PM _{2.5} (µg/m ³)			SO ₂ (ppb)		
Unit Code	First	Second	Third	First	Second	Third	First	Second	Third
DDPEC_CC1	37	33	29	17	12	11	1	1	1
FREC_CC2							0	0	0
TXCTY_CC1							3	2	2
CHAMON_CTG_0101	31	30	29						
THW_THWGT32	37	37	36						
GBY_GBYGT74	40	36	35	20	14	14			
PHR_CLCWA_5UNITS	27	18	17						
LH_LYN_30UNITS	31	30	29						
SOE_SEWP_10UNITS	37	33	29	17	12	11	1	1	1
FEGC_UNIT1							0	0	0

Note: For NO₂ and SO₂ these are 1-hour averages; PM_{2.5} is a daily average.

Table 2b. Top 3 Highest Air Concentrations (as Percentage of Air Quality Standard^a) Monitored Within 10 km of the Power Generation Units

Power Unit	NO ₂			PM _{2.5}			SO ₂		
Unit Code	First	Second	Third	First	Second	Third	First	Second	Third
	37%	33%	29%	48%	34%	30%	1%	1%	1%
FREC_CC2							0%	0%	0%
TXCTY_CC1							3%	3%	3%
CHAMON_CTG_0101	31%	30%	29%						
THW_THWGT32	37%	37%	36%						
GBY_GBYGT74	40%	36%	35%	56%	40%	39%			
PHR_CLCWA_5UNITS	27%	18%	17%						

⁴ CO is not shown because the values were <1 percent of the NAAQS.

Power Unit	NO ₂			PM _{2.5}			SO ₂		
Unit Code	First	Second	Third	First	Second	Third	First	Second	Third
LH_LYN_30UNITS	31%	30%	29%						
SOE_SEWP_10UNITS	37%	33%	29%	48%	34%	30%	1%	1%	1%
FEGC_UNIT1							0%	0%	0%

^a The 1-hour NO₂ standard is 100 ppb, 1-hour SO₂ standard is 75 ppb, and 24-hour PM_{2.5} standard is 35 µg/m³.

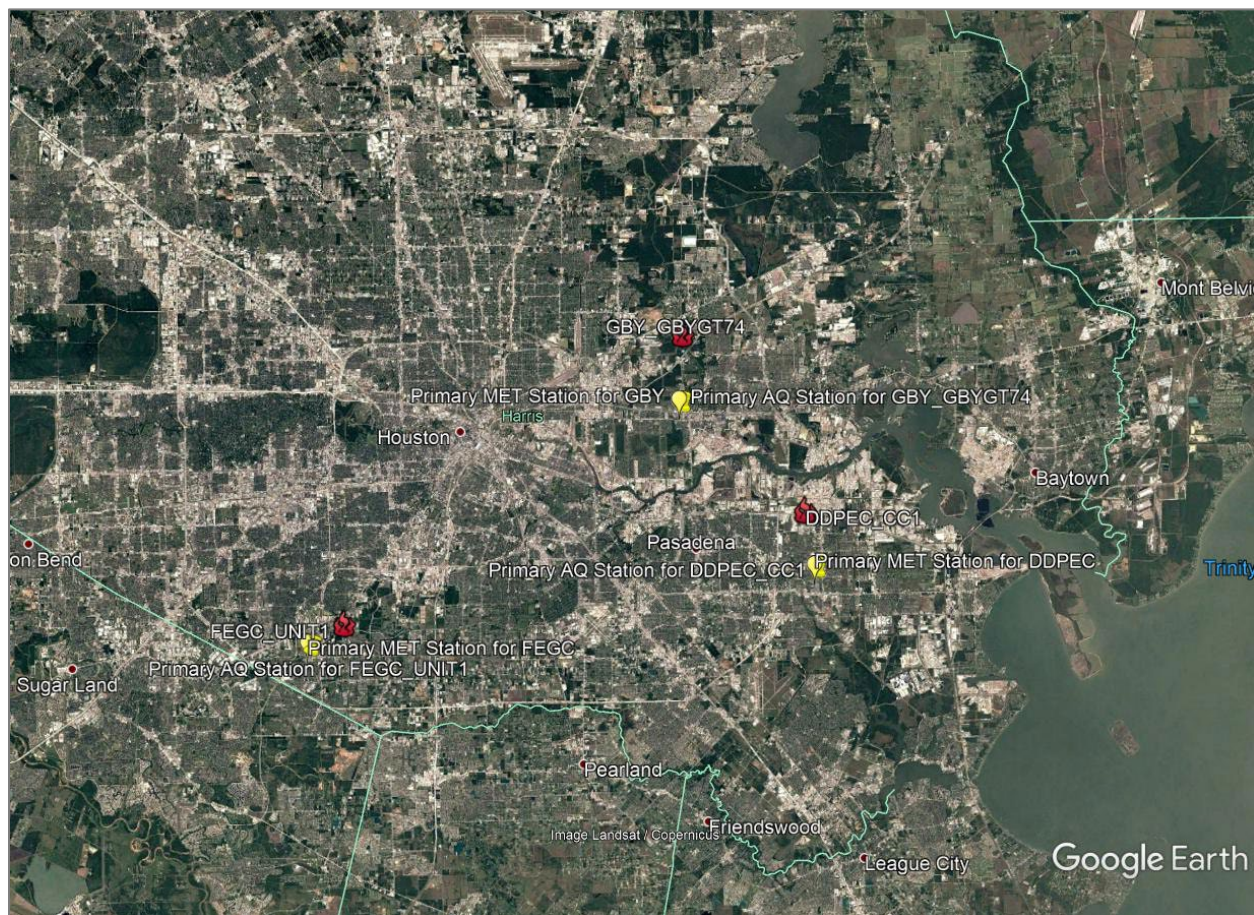
1.1.2 Downwind Air Quality Monitoring Sites

Besides being in close proximity to the power unit, an air quality monitoring station must also be oriented in the downwind direction of the power unit. Table 3 shows the percentage of time that the air quality monitoring station was downwind of the power unit. As shown, only one air quality monitoring site was downwind more than 50 percent of the hours. All other pairs of air quality monitoring stations and power units only had the correct alignment window 25 percent or less of the time. The air quality monitoring unit paired with the Deer Park Energy Center (DDPEC_CC1) power unit was downwind more than half the hours. This was the best pairing of any power unit and air quality station and shows good supporting evidence that the power units' excess emissions were unlikely to have caused an exceedance of the NAAQS (except on February 16, 2021, when the monitoring stations only had valid measurements for 20 percent of the hours that day). All other meteorological/air quality station pairs had too few hours to draw a conclusion. Figure 1 shows the locations of three of the power units relative to the air monitoring stations in Harris County.

Table 3. Power Unit Pairings With Nearby Meteorological Stations and Percentage of Time Downwind

Power Unit Code	Distance to MET Station (km)	AQ Station Direction – Lower Bound	AQ Station Direction – Upper Bound	% of MET Station Data Within +/-20 Degree Range of AQ Station Location
DDPEC	4.9	320°	360°	58%
FREC	10.3	320°	360°	25%
TXCTY	1.4	220°	260°	3%
CHAMON	8.6	0°	40°	6%
THW	17.5	220°	260°	<1%
GBY	5.6	345°	25°	25%
PHR	11.1	135°	175°	<1%
LH	1.2	100°	140°	10%
SOE	5.0	185°	225°	1%
FEGC	3.5	25°	65°	3%

Figure 1. Location of Three Power Units Operating in Harris County and the Paired Air Monitoring Station



1.1.3 Meteorological Conditions Conducive to High Concentrations

Wind Speed

As discussed, lower wind speeds result in poorer dispersive conditions that lead to higher air concentration levels. Average wind speeds for February, based on the 23-year average (1998–2020) from the Houston Aldine site (EPA Airs ID# 48-201-0024), is 6.2 mph. During the 5-day emergency-use period, the winds were slightly higher (14 percent) than the average wind speed of 7.0 mph. Thus, the slightly higher wind speeds are favorable to having lower air concentrations.

Temperature

As discussed, lower temperatures will lead to increased buoyancy, resulting in lower air concentrations. The climatological average air temperature for February at the Houston International Airport is 57.7°F. During the 5-day event, the average air temperature was 28.4°F, almost 30°F below average. These substantially colder temperatures are favorable to having lower ground-level air concentrations, assuming the plume rise from the power units is sufficiently high that these concentrations are not trapped in a shallow stable layer (i.e., temperature inversion) near the surface.

Mixing Heights

We determined mixing height by using the same method as the historical data from Lake Charles (the closest upper air station to Harris County). The February morning mean mixing height during the 5-day emergency event was 530 m, and the afternoon mixing height was 607 m. This compares with a climatological morning mixing height of 319 m in February and a climatological afternoon mixing height of 822 m. The higher mixing height observed during the event reduced the tendency for the trapping of air pollutants in a shallow layer near the Earth's surface, so air concentrations should be lower due to higher mixing height. The lower mixing heights observed during the event in the afternoon relative to the climatological average is the reverse of the morning, but the mean depth of the mixed layer is still higher than the morning period, so in general, concentrations are lower in the afternoon than the morning if emissions are the same.

1.1.4 Emission Rates: ERCOT versus CEMS

To better understand the emissions data, we graphically displayed the ratio of the ERCOT emission rates for NO_x to the CEMS NO_x emission rates for every hour using three representative emission profiles observed during our review of the ERCOT dataset. We report results for three representative types of findings. These are:

1. Peaking Plant, where the ERCOT is thought to be a large fraction of the CEMS data
2. Large amount of volatility in the ERCOT dataset
3. Does not make sense (ERCOT emission rate >> CEMS emission rate)

In no case should the ERCOT to CEMS ratio be greater than 1.

The three representative stations are:

1. Port Comfort Peaking Unit 2
2. Chamon Power Unit 1
3. Bosque CCP-GT-1

Figure 2 shows the ratio of the ERCOT NO_x emission rate to the CEMS NO_x emission rate for Port Comfort Peaking unit, with most hours reporting a ratio between 60 to 80 percent of the CEMS emission rate and with the unit off during most of February 18, 2021. A few anomalous hours occur where the ERCOT-to-CEMS ratio exceeds 1. Overall, this pattern appears to be a reasonable behavior.

Figure 2. Port Comfort Peaking Unit Hourly ERCOT/CEMS Emission Ratio During Emergency Period

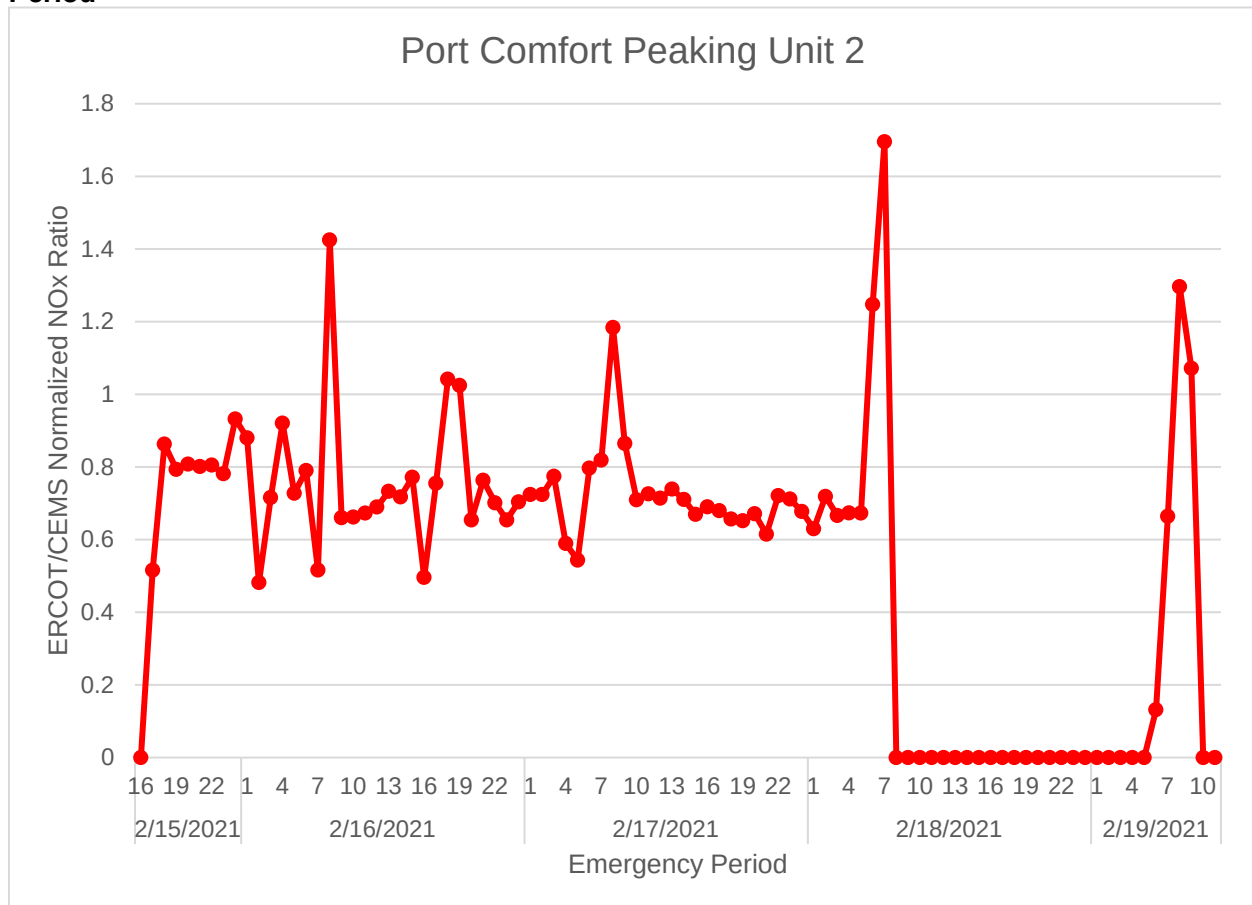


Figure 3 shows the ratio of the ERCOT NO_x emission rate to the CEMS NO_x emission rate for the Port Chamon unit, with most hours having a value of less than 100 percent. There are a few hours with a ratio excursion that well exceeds a ratio of 1. Overall, this pattern can likely be explained if further information can be obtained from the plant about the few hourly ratio excursions that were much greater than 1.

Figure 3. Chamon Unit 1 Hourly ERCOT/CEMS Emission Ratio During Emergency Period

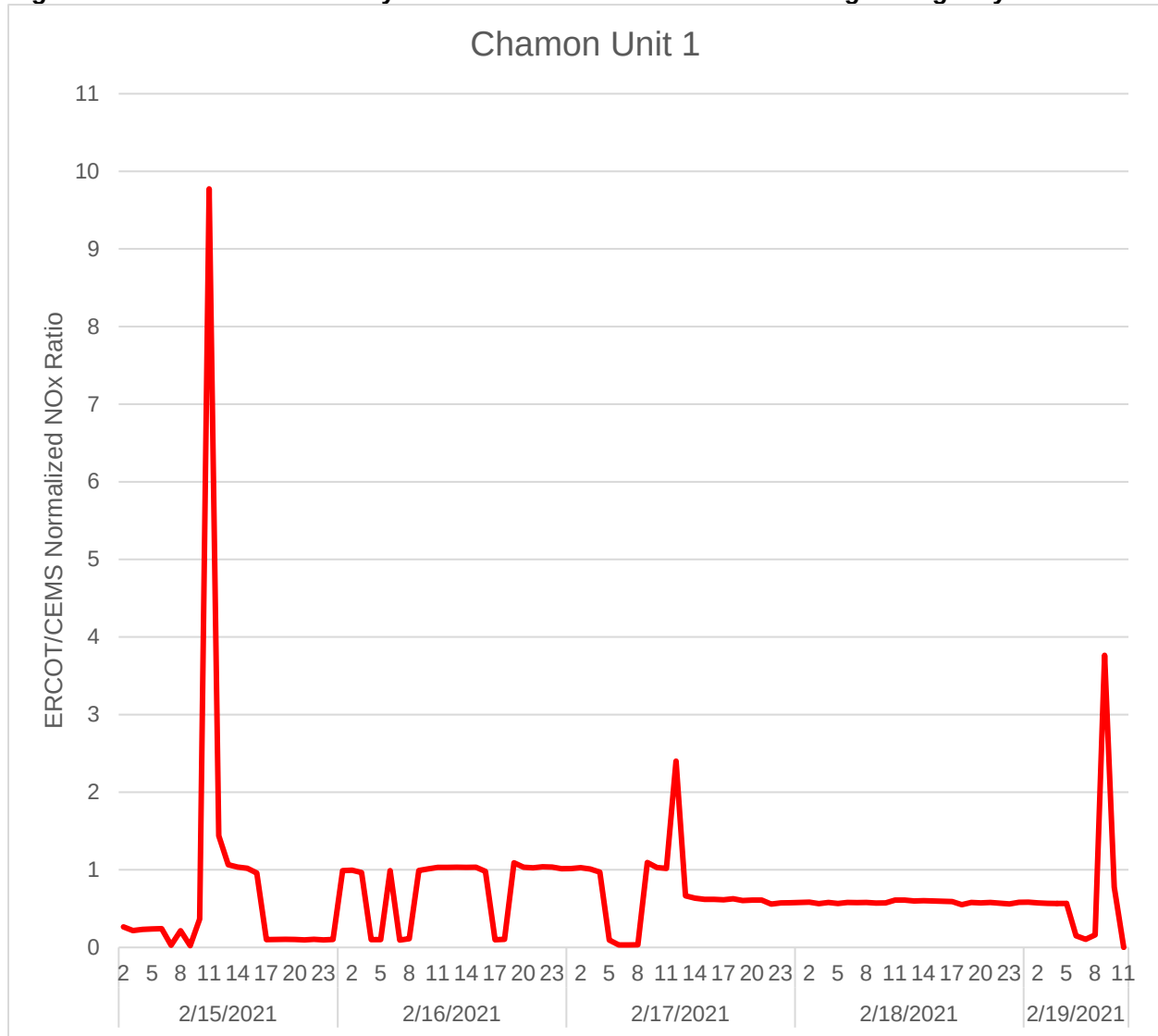
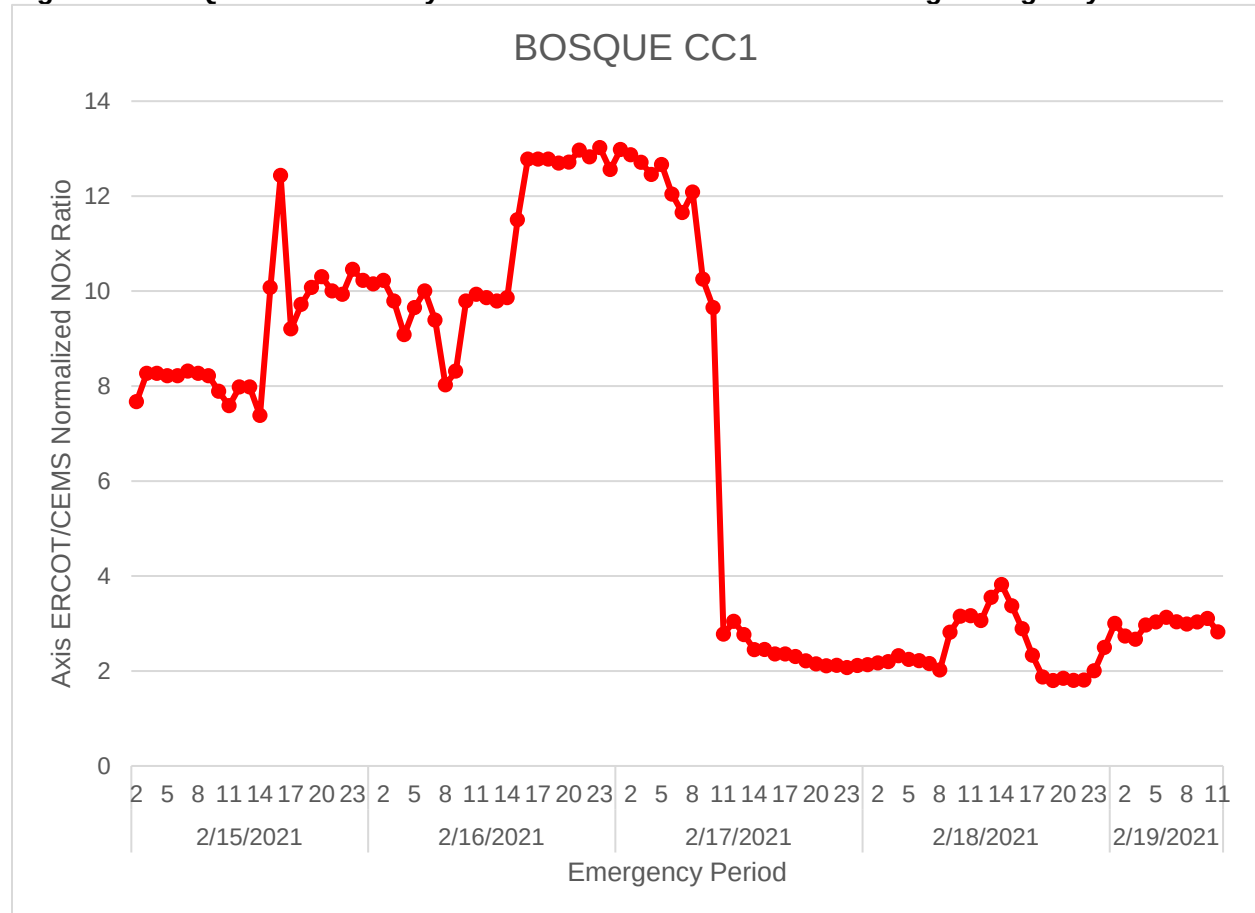


Figure 4 shows the ratio of the ERCOT NO_x emission rate to the CEMS NO_x emission rate for the BOSQUE unit, with all hours having a ratio in excess of 1, or less than 100 percent, but a few hours having a ratio excursion that well exceeds a ratio of 1. In fact, no ratio is less than 2, with a maximum of 13. Overall, these high values in comparison to the CEMS data are irregular. We suspect that incorrect values may have been reported by BOSQUE, as well as other units that exhibited similar behavior. However, further discussion with the plant is needed to clarify this finding.

Figure 4. BOSQUE Unit 1 Hourly ERCOT/CEMS Emission Ratio During Emergency Period



1.2 Conclusions – Air Quality Analysis

We reviewed ambient air quality monitoring data, meteorological data, and emission information for the power units that operated in exceedance of their permitted levels during the emergency use of power generation authorization under Section 202(c). We paired air quality monitoring stations with power units that were near each other. We found pairings for 10 of the 14 unique power generation units, most often for NO₂. We found no exceedances of the NAAQS standards; however, many of the air quality stations were missing air quality measurements on February 16 and 17, 2021. The highest concentration, to any air quality standard, was for the 24-hour PM_{2.5} standard at 56 percent of the exceedance threshold value. Further review of the air quality monitoring station and power unit data showed just one air quality monitoring station downwind of the power unit for the majority of hours during the emergency use period. A review and discussion of the meteorological conditions (e.g., wind speeds, temperature, mixing heights)

during the emergency period showed that the meteorology was conducive to better mixing and dispersion than average conditions in February. Reported incremental emissions did not compare favorably with the CEMS data available for NO_x.

Although no exceedances for the NAAQS occurred during the emergency use period, the large percentage of missing data, particularly on February 16 and 17, 2021, make it difficult to conclusively conclude that no violation of the NAAQS may have occurred. Furthermore, the limited number of downwind air quality monitors in close proximity to the power units makes it difficult to definitively conclude there were no air quality exceedances. However, based on the weight-of-evidence approach presented herein, it appears unlikely that the power units may have caused an exceedance of the NAAQS.

2 Environmental Justice Implications for the Affected Population

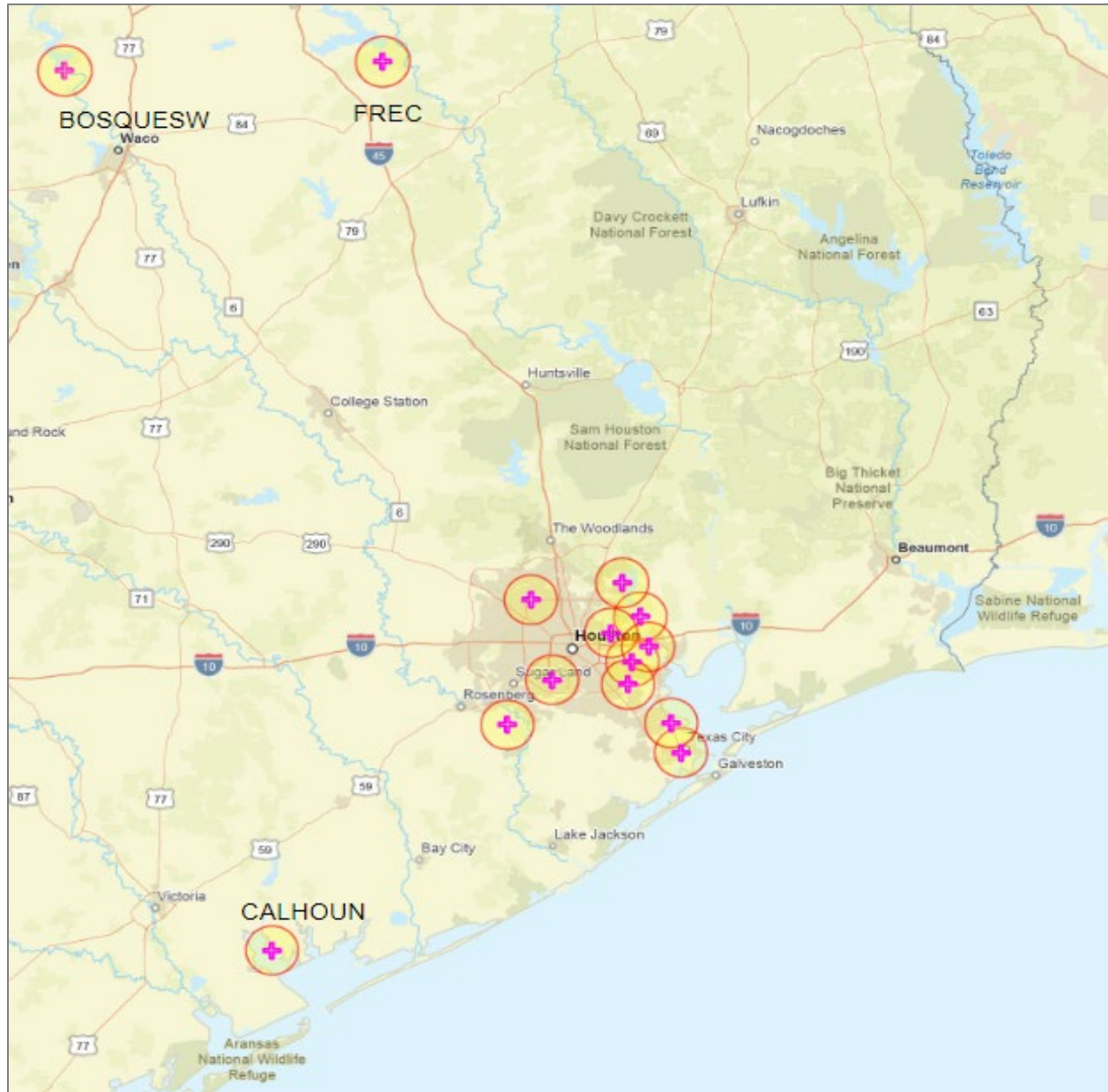
This section highlights the potential environmental justice (EJ) implications of the affected population in the region of interest. Our evaluation was based on data from U.S. Environmental Protection Agency's (EPA) EJSCREEN tool, available at ejscreen.epa.gov/mapper. EJSCREEN is a tool EPA has developed over the years to allow users to evaluate potential EJ impacts in different parts of the country using a GIS-based mapping platform. The tool allows users to combine demographic and environmental information on a user-selected area. The data used for these purposes in EJSCREEN are based on publicly available data sources, such as the American Community Survey from the Census Bureau for demographic data and various EPA data sources for environmental indicators. We used this screening tool for this analysis because it provides a method consistent with EPA's approach for defining EJ vulnerabilities for affected populations.

2.1 Analyzing Demographic Characteristics of Nearby Population

In order to identify the vulnerable population around these 14 unique power plants and 27 units that are likely to be impacted by any potential exceedances during the 5-day period, we extracted the demographic and environmental characteristics of those living within a pre-specified 5- and 10-km radius around each power plant. Note that we conducted this analysis at the plant level (as opposed to the unit level) because the unique location coordinates were available only at the plant level.

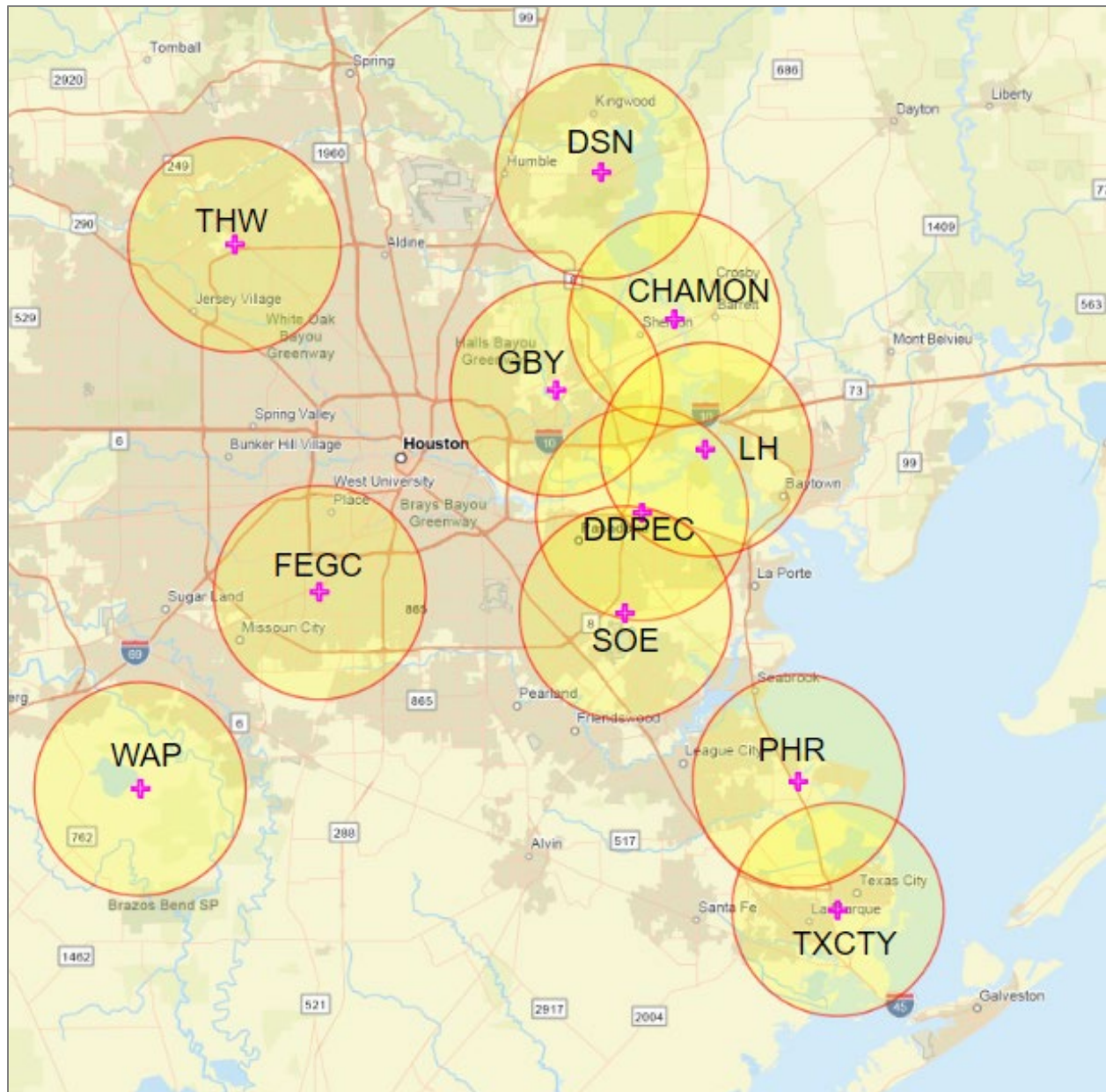
Figure 6 below overlays 10-km circles around the individual power plants. Using a 10-km radius around these plants captures a greater share of the potentially affected population and is consistent with the air quality analysis discussed above. It also creates more overlapping areas, which increases the EJ concerns for the people living in those areas. This is discussed in more detail below.

Figure 6. 10-km Radius Around Plants



Given the relative proximity of some of these plants, particularly those in the Houston area, several of the 10-km circles tended to have some overlapping areas among them, which suggests that some members of the population are likely to be affected by activities from multiple plants and are therefore exposed to higher EJ risks than others. In order to analyze those risks, Figure 7 below focuses on the plants around Houston to identify intersecting circles.

Figure 7. Intersecting Areas With 10-Km Radius Around the Plants



Using these custom boundaries, ICF extracted demographic and environmental data from EJSCREEN to identify potential EJ vulnerabilities for the population living around these plants. Table 4 indicates the age ranges of populations in both the 5- and 10-km radii from the power plant indicated. As the table shows, there is a wide variability of the exposure in the 5- and 10-km ranges around these plants. The total population exposed to any potential EJ concerns within a

5-km radius of these plants can range from about 50 people to over 100,000 people, with FREC being the lowest and FEGC being the highest. Similar patterns hold for the 10-km radii, except the range is from about 900 to over 500,000 people.

Table 4. Distribution of the Affected Population by Age

Power Plant	5-Km Radius					10-Km Radius				
	Total Population	0 to 4	5 to 17	18 to 64	65+	Total Population	0 to 4	5 to 17	18 to 64	65+
BOSQUE	1,989	5%	12%	55%	29%	4,176	4%	13%	55%	28%
CALHOUN	751	10%	17%	65%	8%	11,735	7%	17%	59%	17%
CHAMON	10,469	6%	20%	60%	15%	90,052	9%	21%	62%	8%
DDPEC	53,680	7%	21%	61%	10%	276,938	8%	22%	61%	9%
DSN	67,599	8%	22%	61%	9%	201,458	7%	21%	61%	11%
FEGC	112,417	7%	18%	63%	12%	568,858	8%	18%	64%	10%
FREC	56	4%	20%	61%	16%	868	5%	16%	65%	14%
GBY	79,700	9%	21%	62%	8%	258,116	8%	22%	61%	9%
LH	12,839	9%	21%	57%	14%	128,113	8%	22%	61%	10%
PHR	18,722	9%	19%	62%	10%	93,580	8%	19%	61%	12%
SOE	56,345	6%	18%	63%	13%	394,451	8%	20%	62%	10%
THW	107,393	7%	20%	63%	10%	461,570	7%	20%	63%	10%
TXCTY	43,452	8%	19%	59%	15%	71,729	7%	18%	60%	16%
WAP	745	8%	20%	61%	11%	54,391	7%	23%	61%	10%

The majority of the people living in these areas seem to fall into what is likely the least vulnerable from an age perspective for EJ concerns. As the table above shows, more than 50 percent of the population falls within the 18–64 age group. However, some of these plants do have a relatively large share of the population that can be considered to be more susceptible to EJ problems. For example, BOSQUE has the highest percentage of people age 65+ in a 5- and 10-km radius, but is among the lowest in total population. Also, four of these plants have roughly 30 percent of the population below the age of 18, with about 20 percent or so in the 5–17 age group and the remaining 10 percent or so in the 0–4 age group.

Table 5 shows the distribution of the population by household incomes in both the 5- and 10-km radii. Note that the income data presented below are for households and not in per capita terms, which is different from how the data are shown in the other demographic tables.

Many of these plants have a relatively large share (20–30 percent) of the households that have incomes less than \$25,000 or close to the federal poverty line. Among them, GBY and TXCTY have the highest percentage (13 percent for the 10-km radius) of people with incomes below \$15,000 for a household, which is likely to exacerbate potential EJ concerns for this region. Correspondingly, GBY and TXCTY have the lowest percentage of people with a household income above \$50,000, falling between 40 and 50 percent for both radii. This indicates that the majority of people in these radii have household incomes below \$50,000, and both of these power plants are among those with a larger surrounding population.

Table 5. Distribution of the Affected Households by Income

Power Plant	5-Km Radius					10-Km Radius				
	Total Households	< \$15,000	\$15,000–\$25,000	\$25,000–\$50,000	\$50,000 +	Total Households	< \$15,000	\$15,000–\$25,000	\$25,000–\$50,000	\$50,000 +
BOSQUE	809	10%	14%	23%	52%	1,812	11%	15%	22%	52%
CALHOUN	285	7%	7%	20%	65%	4,137	11%	8%	27%	53%
CHAMON	3,418	7%	8%	23%	62%	28,248	7%	7%	20%	66%
DDPEC	16,779	7%	9%	21%	63%	85,473	9%	10%	24%	56%
DSN	22,212	4%	4%	13%	78%	67,417	6%	5%	15%	74%
FEGC	39,063	11%	8%	21%	59%	207,938	12%	11%	22%	55%
FREC	30	10%	17%	17%	57%	533	10%	20%	19%	51%
GBY	24,514	11%	11%	30%	48%	77,689	13%	13%	30%	45%
LH	4,234	12%	10%	23%	55%	39,892	10%	9%	23%	59%
PHR	6,527	11%	12%	21%	56%	34,256	9%	8%	18%	64%
SOE	19,748	7%	7%	19%	68%	130,051	9%	8%	23%	60%
THW	34,429	7%	9%	25%	59%	155,731	8%	8%	24%	60%
TXCTY	15,489	15%	13%	30%	41%	26,149	13%	12%	27%	48%
WAP	307	2%	1%	9%	88%	16,375	3%	2%	8%	86%

The table below shows the breakdown of the population in these regions by race, in both the 5-km and 10-km radii. Race information is broken down to show populations that self-identify as Black, Hispanic, Other non-White (i.e., American Indian, non-Hispanic Asian, Pacific Islander, or another race), and White.

Not surprisingly, some of the regions with the lowest income distribution also have the largest minority populations. For example, the area around GBY, which had one of the largest shares of the low-income population, also has around 90 percent Black and Hispanic populations. TXCTY, which also had a high proportion of the low-income population around it, is about two-thirds Black and Hispanic. Among the others, the population around FEGC, THW, and LH is also high in non-White or minority populations.

Table 6. Distribution of Population by Race

Power Plant	5-Km Radius					10-Km Radius				
	Total Population	Black	Hispanic	Other Non-white	White	Total Population	Black	Hispanic	Other Non-white	White
BOSQUE	1,989	1%	7%	1%	91%	4,176	1%	7%	1%	90%
CALHOUN	751	5%	29%	9%	57%	11,735	4%	55%	7%	34%
CHAMON	10,469	21%	39%	3%	38%	90,052	18%	46%	4%	32%
DDPEC	53,680	2%	55%	2%	41%	276,938	4%	65%	2%	29%
DSN	67,599	17%	27%	6%	51%	201,458	15%	25%	5%	54%
FEGC	112,417	32%	39%	7%	22%	568,858	31%	35%	11%	23%
FREC	56	13%	7%	4%	77%	868	24%	7%	4%	65%
GBY	79,700	30%	59%	2%	9%	258,116	29%	61%	2%	9%
LH	12,839	7%	51%	3%	40%	128,113	14%	53%	4%	29%
PHR	18,722	4%	33%	7%	55%	93,580	9%	27%	5%	59%
SOE	56,345	3%	42%	10%	45%	394,451	6%	55%	7%	32%
THW	107,393	20%	40%	16%	24%	461,570	21%	39%	12%	29%
TXCTY	43,452	29%	32%	5%	34%	71,729	27%	29%	4%	40%
WAP	745	19%	22%	11%	48%	54,391	11%	13%	34%	41%

2.2 Combining Demographic Information With Environmental Indicators

In order to understand the EJ vulnerabilities of the population living around these power plants, we analyzed various pollutant indicators from EJSCREEN and used their estimated percentile rankings to compare the potential vulnerabilities across the various plants. The estimated percentile rankings, developed by EPA, combine the environmental indicator with the appropriate demographic data to account for the vulnerable groups in the calculation of the EJ indicator. In this context, EPA defines the vulnerable groups as the average of the count of minorities and low-income households. In terms of the individual percentile rankings, a low number signifies that this group is relatively better off than the rest of the state population, whereas a high ranking signifies a relatively worse off situation than the rest of the state. As an example, if a certain ranking is 80, it means that this place is at the 80th percentile, which implies that only 20 percent of the state population experiences pollution that is higher than those experienced by people in this region. Thus, as a general principal, percentile rankings that are on the high side generally imply the region in question is comparatively worse off than other places in the state.

Table 7 shows the relative rankings of the various populations around these plants that are exposed to the various environmental indicators of interest (see Table 7 notes for definitions of these pollutant indicators). We present the percentile rankings for both the 5- and 10-km radii around each power plant. Table 7 also presents a calculated average percentile ranking in order for us to easily compare across the various plants. Average percentile rankings greater than 50 percent are highlighted in light blue and indicated with an asterisk (*). Note that these averages are simple arithmetic means, which essentially puts equal weights on each environmental indicator, irrespective of their implications on human health. Thus, one could argue that these averages are not reflective of the individual pollutants' effect on the vulnerable populations. We included them here for easy comparison across the groups without any value judgement on the individual pollutants.

Table 7. Percentile Ranking of Various Environmental Indicators

Power Plant	5-Km Radius					
	Particulate Matter (PM _{2.5} in ug/m3)	NATA Diesel PM (ug/m3)	NATA Air Toxics Cancer Risk (risk per MM)	NATA Respiratory Hazard Index	Hazardous Waste Proximity (facility count/km distance)	Average Percentile Ranking
BOSQUE	26	30	28	28	35	29.4
CALHOUN	40	38	40	40	50	41.6
CHAMON	57	59	69	62	60	61.4*
DDPEC	52	62	64	54	85	63.4*
DSN	16	16	12	15	25	16.8
FEGC	80	87	83	81	93	84.8*
FREC	31	33	31	31	32	31.6
GBY	91	92	95	95	96	93.8*
LH	62	67	84	68	95	75.2*
PHR	41	40	40	40	49	42
SOE	44	51	50	46	66	51.4*
THW	83	90	83	85	93	86.8*
TXCTY	62	61	61	61	92	67.4*
WAP	11	13	12	12	20	13.6
Power Plant	10-Km Radius					
	Particulate Matter (PM _{2.5} in ug/m3)	NATA Diesel PM (ug/m3)	NATA Air Toxics Cancer Risk (risk per MM)	NATA Respiratory Hazard Index	Hazardous Waste Proximity (facility count/km distance)	Average Percentile Ranking
BOSQUE	22	27	23	23	33	25.6
CALHOUN	51	48	48	47	46	48
CHAMON	81	80	94	87	94	87.2*
DDPEC	70	77	85	79	95	81.2*
DSN	30	32	28	30	50	34
FEGC	77	86	80	78	87	81.6*
FREC	48	44	48	48	42	46
GBY	89	91	95	94	97	93.2*
LH	78	80	92	87	96	86.6*
PHR	31	26	26	30	58	34.2
SOE	66	75	77	69	86	74.6*
THW	78	86	79	80	87	82*
TXCTY	56	56	56	56	87	62.2*
WAP	50	54	49	49	48	50

Particulate Matter (PM_{2.5} in ug/m3) – PM_{2.5} levels in the air, measured in µg/m3 annual average.

NATA Diesel PM (ug/m3) – Diesel particulate matter level in the air, measured in µg/m3.

NATA Air Toxics Cancer Risk (risk per MM) – Lifetime cancer risk from inhalation of air toxics.

NATA Respiratory Hazard Index – Air toxics respiratory hazard index (the ratio of exposure concentration to health-based reference concentration).

Hazardous Waste Proximity (facility count/km distance) – The count of hazardous waste facilities (TSDFs and LQGs) within 5 km (or nearest beyond 5 km), each divided by the distance in kilometers.

In order to identify which of these regions may have a vulnerable population exposed to disproportionately higher environmental justice concerns than the rest of the state, we chose an arbitrary 50-percent threshold and highlighted in the tables above those regions that are above that threshold. The results imply that the vulnerable populations living in these regions are experiencing higher levels of EJ concerns than a majority of the rest of Texas. Unsurprisingly, among these regions around power plants that are of higher EJ concerns, the ones that we identified above as having the most vulnerable populations are the ones with the highest average ranking. This includes populations around power plants GBY, FEGC, and THW as the most at-risk, with an average percentile ranking of over 80. Following those are SOE, LH, and TXCTY, with rankings between 60 and 70. Some power plants seem to jump considerably, moving from the 5-km to the 10-km radii. These include CHAMON and DDPEC, where the rankings jump from the 60s to 80s when we move from the 5-km to 10-km radius. Thus, when we analyze the vulnerable population within a 10-km radius of these plants, the majority of these power plants (i.e., 8 out of 14) have a baseline EJ vulnerability, higher than the rest of the state, affecting the population living near these power plants.

2.3 Population in Close Proximity to Multiple Plants

As discussed previously (see Figure 7), several of these power plants, particularly those around the Houston area, have significant overlapping regions when we analyze the populations within a 10-km radius around these plants. Populations living in these “intersecting circles” are likely to face even higher EJ concerns, given that they may have been exposed to higher emissions from multiple power plants. Here we present data for these population groups in these intersecting circles and their potential for higher EJ concerns.

Table 8 below shows the age distribution of the population living in these intersecting regions with two or more 10-km radii. The intersecting radii are of different sizes, which is part of the reason for the differences in population between areas. Overall, the percentage of people in each intersecting region that are between ages 0 and 4 are comparable to those 65+, with the latter only a slightly higher percentage in most areas. In total, approximately 12 percent, or about 325,000 of the 2.6 million total population living within a 10-km radius of all power plants, live in these intersecting regions and are thus likely to face higher levels of baseline EJ concerns than those that live outside of these intersecting regions. Most of this population group lives in an area that has two plants within 10 km, but about 20 percent of them live in areas that are close to three or more power plants.

Table 8. Distribution of the Affected Population in the Intersecting Regions by Age

Power Plants	10-Km Radius Intersections				
	Total Population	0 to 4	5 to 17	18 to 64	65+
CHAMON & DSN	14,817	10%	19%	65%	5%
GBY & CHAMON	21,330	10%	21%	63%	6%
GBY & DDPEC	22,002	9%	23%	60%	8%
LH & CHAMON	11,605	7%	20%	61%	12%
LH & DDPEC	6,337	10%	20%	60%	10%
LH & GBY	1,073	3%	22%	66%	10%
PHR & TXCTY	8,678	7%	17%	61%	16%
SOE & DDPEC	175,158	8%	21%	61%	10%
DDPEC & LH & GBY	28,277	8%	25%	59%	8%
GBY & LH & CHAMON	10,371	8%	25%	62%	6%
LH & DDPEC & CHAMON	3,495	9%	24%	56%	10%
LH & DDPEC & SOE	15,072	5%	19%	65%	11%
DDPEC & LH & GBY & CHAMON	7,275	7%	25%	62%	5%

Table 9 shows the household income of populations living in intersections of two or more 10-km radii. Household incomes for the intersecting regions are comparable to the incomes of the 5- and 10-km radii. Two intersecting areas have a majority of households with incomes less than \$50,000, which are the LH/DDPEC/CHAMON intersection and the GBY/DDPEC intersection. Alternatively, the highest percentage of households with incomes over \$50,000 is 81 percent, in the intersection of CHAMON and DSN.

Table 9. Distribution of the Affected Population in the Intersecting Regions by Income

Power Plants	10-Km Radius Intersections				
	Total Households	< \$15,000	\$15,000–\$25,000	\$25,000–\$50,000	\$50,000 +
CHAMON & DSN	4,652	3%	4%	12%	81%
GBY & CHAMON	6,424	4%	5%	26%	65%
GBY & DDPEC	6,320	12%	15%	29%	44%
LH & CHAMON	3,972	9%	11%	24%	56%
LH & DDPEC	1,989	11%	12%	24%	54%
LH & GBY	281	2%	2%	20%	76%
PHR & TXCTY	3,095	13%	9%	25%	53%
SOE & DDPEC	55,947	10%	10%	24%	57%
DDPEC & LH & GBY	7,730	7%	12%	29%	52%
GBY & LH & CHAMON	2,873	6%	3%	20%	71%
LH & DDPEC & CHAMON	959	13%	20%	21%	46%
LH & DDPEC & SOE	4,917	2%	5%	17%	75%
DDPEC & LH & GBY & CHAMON	2,081	8%	5%	20%	67%

Table 10 below shows the racial composition of the population living in intersections of two or more 10-km substation radii. Most of these intersecting regions have a predominantly minority population, with the Hispanic population comprising the bulk. The intersection with the highest total population is also among the highest in percentage of non-Whites, SOE/DDPEC. With a population over 100,000 greater than the next largest population, 69 percent of the population is either Black, Hispanic, or another non-White race. Other areas with a high percentage of non-White races are GBY/LH/CHAMON, DDPEC/LH/GBY/CHAMON, and LH/GBY.

Table 10. Distribution of the Affected Population in the Intersecting Regions by Race

Power Plants	Race of Population				
	10-Km Radius Intersections				
	Total Population	Black	Hispanic	Other Non-White	White
CHAMON & DSN	14,817	21%	28%	5%	46%
GBY & CHAMON	21,330	24%	54%	6%	16%
GBY & DDPEC	22,002	4%	82%	1%	13%
LH & CHAMON	11,605	7%	47%	1%	44%
LH & DDPEC	6,337	0%	56%	1%	43%
LH & GBY	1,073	37%	44%	7%	12%
PHR & TXCTY	8,678	19%	28%	4%	48%
SOE & DDPEC	175,158	2%	64%	3%	31%
DDPEC & LH & GBY	28,277	11%	72%	1%	16%
GBY & LH & CHAMON	10,371	22%	66%	3%	9%
LH & DDPEC & CHAMON	3,495	0%	67%	2%	31%
LH & DDPEC & SOE	15,072	0%	29%	6%	65%
DDPEC & LH & GBY & CHAMON	7,275	25%	65%	2%	9%

Table 11 below shows the EJ indexes in intersections of two or more 10-km substation radii. As discussed above, the environmental indicator listed in the Table 11 incorporates the value of the pollutant within the radius, as well as the percentage of minority people and low-income people in the radius. The table also presents the “average” percentile ranking as a way to ordinaly rank these intersecting circles. Average percentile rankings greater than 50 percent are highlighted in light blue and indicated with an asterisk (*).

Table 11. Environmental Justice Index in State Percentiles for People Living in the Intersecting Points of Two or More Substations in a 10-km Radius

Power Plants	10-Km Radius Intersections					Average Percentile Ranking
	Particulate Matter (PM 2.5 in ug/m3)	NATA Diesel PM (ug/m3)	NATA Air Toxics Cancer Risk (risk per MM)	NATA Respiratory Hazard Index	Hazardous Waste Proximity (facility count/km distance)	
CHAMON & DSN	42	44	43	43	41	42.6
GBY & CHAMON	94	93	97	96	94	94.8*
GBY & DDPEC	78	85	89	94	98	88.8*
LH & CHAMON	54	60	71	59	75	63.8*
LH & DDPEC	64	69	90	72	97	78.4*
LH & GBY	68	73	81	79	94	79*
PHR & TXCTY	65	62	65	63	87	68.4*
SOE & DDPEC	64	74	78	68	92	75.2*
DDPEC & LH & GBY	88	89	97	96	99	93.8*
GBY & LH & CHAMON	96	95	99	98	99	97.4*
LH & DDPEC & CHAMON	78	80	97	84	98	87.4*
LH & DDPEC & SOE	13	10	2	10	0	7
DDPEC & LH & GBY & CHAMON	95	93	99	97	99	96.6*

Using the same 50 percent threshold, the table shows which of these intersecting circles have a value higher than 50 percent, which implies that the population living in these intersecting regions have a higher level of exposure to EJ concerns than a majority of the rest of the population in Texas. Only two intersections have an average state percentile under 50 percent, which are LH/DDPEC/SOE and CHAMON/DSN. Thus, almost 85 percent of the population living in these intersecting regions have higher exposure to EJ concerns than the rest of the state. Given that these population groups, consisting mostly of minority populations, live near multiple power plants (and presumably other stationary sources), it is not surprising that these groups are more vulnerable when it comes to environmental justice considerations compared to the rest of the state.

2.4 Conclusion – Environmental Justice Analysis

Using data from EPA's EJSCREEN, it appears that people of color and those with limited socioeconomic means in and around the Houston area are more vulnerable to environmental justice considerations compared to the rest of Texas. Given the paucity of data discussed in the air quality analysis above, we could not determine whether the EJ concerns for these groups were exacerbated during those 5 days in February 2021, when DOE authorized the emergency use of power generation under Section 202(c) of the Federal Power Act. However, analyzing the *baseline, business-as-usual* EJ concerns for the population around these power plants does indicate that a majority of the population living here are minority with limited socioeconomic opportunities and that they are also vulnerable to higher levels of pollution under those baseline conditions.

3 References

U.S. Environmental Protection Agency. 1972. *Mixing Heights, Wind Speeds, and Potential for the Urban Air Pollution Throughout the Contiguous United States*. Prepared by George Holzworth. Research Triangle Park, NC: Office of Air Program, AP-101.

Appendix – Generators

Generator Name	Fuel Type	Resource Owner Name	County	Unit Code
East Water Plant	Distillate Fuel Oil	NRG Energy Services	Harris	CL_EWP_30UNITS
Lynchburg Pump Station	Distillate Fuel Oil	NRG Energy Services	Harris	LH_LYN_30UNITS
Northeast Water Plant	Distillate Fuel Oil	NRG Energy Services	Harris	DSN_NEWP_10UNITS
Southeast Water Plant	Distillate Fuel Oil	NRG Energy Services	Harris	SOE_SEWP_10UNITS
Clear Lake City WWTP	Distillate Fuel Oil	NRG Energy Services	Harris	PHR_CLCWA_5UNITS
Texas City Power Plant	Natural Gas	Calpine Corporation	Galveston	TXCTY_CC1
Freestone Energy Center Block 1	Natural Gas	Calpine Corporation	Freestone	FREC_CC2
W. A. Parish G4	Natural Gas	NRG Energy Services	Fort Bend	WAP_WAP_G4
T. H. Wharton GT54	Natural Gas	NRG Energy Services	Harris	THW_THWGT54
T. H. Wharton GT56	Natural Gas	NRG Energy Services	Harris	THW_THWGT56
Deer Park Energy Center	Natural Gas	Calpine Corporation	Harris	DDPEC_CC1
Texas City Power Plant	Natural Gas	Calpine Corporation	Galveston	TXCTY_CC1
Freestone Energy Center Block 2	Natural Gas	Calpine Corporation	Bosque	FREC_CC2
Bosque Energy Center Block 1	Natural Gas	Calpine Corporation	Bosque	BOSQUESW_CC1
Bosque Energy Center Block 2	Natural Gas	Calpine Corporation	Bosque	BOSQUESW_CC2
Chamon CT1	Natural Gas	Chamon Power LLC	Harris	CHAMON_CTG_0101
Chamon CT2	Natural Gas	Port Comfort Power LLC	Harris	CHAMON_CTG_0301
Port Comfort CT1	Natural Gas	Chamon Power LLC	Calhoun	CALHOUN_UNIT1
Port Comfort CT2	Natural Gas	Port Comfort Power LLC	Calhoun	CALHOUN_UNIT2
Friendswood Energy Genco	Natural Gas	Friendswood Energy Genco LLC	Harris	FEGC_UNIT1

Source: "ERCOT_DOE_202(c)_Exhibit_A_2-17-2021_2100," ERCOT.

Attachment H

Case 21585 Blumenstock Direct Testimony

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
CONSUMERS ENERGY COMPANY)
for authority to increase its rates for)
the generation and distribution of)
electricity and for other relief.)
_____)

Case No. U-21585

DIRECT TESTIMONY

OF

RICHARD T. BLUMENSTOCK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2024

RICHARD T. BLUMENSTOCK
U-21585 DIRECT TESTIMONY

1 **Q. Please state your name and business address.**

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

4 **Q. By whom are you employed?**

5 A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”).

6 **Q. What is your position with Consumers Energy?**

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

RICHARD T. BLUMENSTOCK
U-21585 DIRECT TESTIMONY

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

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

5 **Q. What is your formal educational experience?**

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

8 **Q. Have you previously provided testimony before the Michigan Public Service**
9 **Commission ("MPSC" or the "Commission")?**

10 A. Yes, I provided testimony in the following MPSC cases:

- 11 • Case No. U-16045-R: Reconciliation of PSCR Costs and Revenues for the
12 Calendar Year 2010;
- 13 • Case No. U-16432-R: Reconciliation of PSCR Costs and Revenues for the
14 Calendar Year 2011;
- 15 • Case No. U-16890: Approval of a PSCR Plan and for Authorization of Monthly
16 PSCR Factors for the Year 2012;
- 17 • Case No. U-16890-R: Reconciliation of PSCR Costs and Revenues for the
18 Calendar Year 2012;
- 19 • Case No. U-17429: Approval of a Certificate of Necessity for the Thetford
20 Generating Plant pursuant to MCL 460.6s and for related accounting and
21 ratemaking authorizations;
- 22 • Case No. U-17317: Approval of a PSCR Plan and for Authorization of Monthly
23 PSCR Factors for the Year 2014;
- 24 • Case No. U-17317-R: Reconciliation of PSCR Costs and Revenues for the
25 Calendar Year 2014;
- 26 • Case No. U-17752: Authority to amend its renewable energy plan approved in
27 Case Nos. U-15805, U-16543, U-16581, and U-17301;
- 28 • Case No. U-17678: Approval of a PSCR Plan and for Authorization of Monthly
29 PSCR Factors for the Year 2015;

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- Case No. U-17678-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2015;
- Case No. U-18250: Application of Consumers Energy for a financing order approving the securitization of qualified costs and related approvals associated with the early termination of the Palisades Nuclear Energy Plant Power Purchase Agreement;
- Case No. U-20134: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief;
- Case No. U-20165: Application of Consumers Energy for approval of its Integrated Resource Plan (“IRP”) pursuant to MCL 460.6t and for other relief;
- Case No. U-20697: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief;
- Case No. U-20963: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief;
- Case No. U-21090: Application of Consumers Energy for Approval of an IRP under MCL 460.6t, certain accounting approvals, and for other relief;
- Case No. U-21224: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief; and
- Case No. U-21389: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to support the Generation Department (“Generation”) requests in this case, and to provide other information that the Company has committed to provide. Toward that end I will:

- Describe Consumers Energy’s coal-, oil-, and gas-fired generation assets, and its hydroelectric and renewable generation assets, including their projected retirement dates;
- Support the Company’s generation asset strategy to: (1) focus continued investment in those generating units (Zeeland Generating Station (“Zeeland Plant”, “ZGS” or “Zeeland”), New Covert Generating Facility (“Covert Plant” or “Covert”), and Jackson Generating Station (“Jackson Plant”, “JGS” or “Jackson”)) which provide the most long-term economic benefit for customers; and (2) sustain safe and environmentally compliant operations for its coal

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generating units (J.H. Campbell (“Campbell”) Units 1, 2, and 3 through their retirement dates;

- Support the periodic outage plans and the Generation Unit Availability and Random Outage Rate (“ROR”) projections for coal generation, oil- and gas-fired peaking generation, and certain hydroelectric power generation, for the projected test year ending February 28, 2026;
- Support the reasonableness and prudence of the capital expenditures for coal generation, oil- and gas-fired peaking generation, and certain hydroelectric power generation for the historical test year ended December 31, 2023, the 14-month bridge period beginning January 1, 2024 and ending February 28, 2025, and the projected test year ending February 28, 2026;
- Support the reasonableness and prudence of the projected investment for Company-owned Solar Generation for the historical test year ended December 31, 2023, the 14-month bridge period beginning January 1, 2024 and ending February 28, 2025, and the projected test year ending February 28, 2026;
- Support the reasonableness and prudence of the Operation and Maintenance (“O&M”) and fuel handling expenses for coal generation, oil- and gas-fired peaking generation, and hydroelectric power for historical test year ended December 31, 2023, the 14-month bridge period beginning January 1, 2024 and ending February 28, 2025, and the projected test year ending February 28, 2026;
- Support the reasonableness and prudence of the O&M expenses for the D.E. Karn (“Karn”) Units 1 and 2 retention and separation incentives for the historical test year ended December 31, 2023;
- Support the reasonableness and prudence of the O&M expenses for the Campbell Units 1, 2, and 3 retention and separation incentives for the historical test year ended December 31, 2023, 14-month bridge period beginning January 1, 2024 and ending February 28, 2025, and the projected test year ending February 28, 2026; and
- Describe the environmental regulations with which the Company’s electric generating fleet must comply.

Q. How is your direct testimony related to the direct testimony of other Company witnesses?

A. Company witness Megan L. Metz’s testimony supports the PSCR costs planned to be incurred, taking into account the periodic outages identified in Exhibit A-41 (RTB-1) and the generating unit availability projections in Exhibit A-42 (RTB-2). Company witness

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Metz also supports the capacity value of the Company's generation assets for the seasonal construct in the MISO Planning Resource Auction ("PRA") in Table 2.

Company witness Thomas P. Clark supports the IRP competitive solicitation process and timeline associated with the IRP solar initiative investment, including the build transfer agreements ("BTAs") and their associated projected capital expenditures. In addition, Mr. Clark supports the competitive solicitation process and timeline associated with the proposed battery energy storage system ("BESS") projected capital expenditures.

Company witness Adam J. Monroe supports capital investments in River Hydro facilities, including the Hardy Dam.

Company witness Josnelly C. Aponte supports the regulatory asset balances and amortization for the recovery of retention and separation expenses at both the Karn and Campbell sites in her direct testimony.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-41 (RTB-1)	Generating Unit Periodic Outages;
Exhibit A-42 (RTB-2)	Generating Unit Availability Projections;
Exhibit A-12 (RTB-3) Schedule B-5.2	Summary of Actual and Projected Electric Capital Expenditures for the Years 2023 through February 2026;
Exhibit A-43 (RTB-4)	Summary of the Generation O&M Expense for the Years 2023 through February 2026;
Exhibit A-44 (RTB-5)	Muskegon River Economic Impact Studies;
Exhibit A-45 (RTB-6)	Karn Unit 3 Cooling Tower Internal Structure Replacement Concept Approval; and

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Exhibit A-46 (RTB-7)

Zeeland Phase I Gas Turbine
Upgrade Concept Approval.

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

A. Yes.

Q. How are the following sections of your direct testimony organized?

A. My direct testimony is divided into four sections. Section I will present exhibits and supporting testimony on the Company's generating assets, its generating asset strategy, and its generating asset projected performance metrics. Included in this section is a discussion of the Company's River Hydro strategy, its compliance with the Settlement Agreement in Case No. U-21224 and the March 1, 2024 Order in Case No. U-21389, the Request for Proposals ("RFP") for the divestiture of the River Hydro facilities, the Company's community outreach activities, and the Company's pursuit of external funding. Section II will describe the environmental regulations with which the Company's electric generating fleet must comply. Section III presents exhibits and supporting testimony for the historical and projected generation capital expenditures. Section IV will present exhibits and supporting testimony for the historical and projected generation O&M expense. This section will include support of the reasonableness and prudence of the O&M expenses for both the Karn Units 1 and 2 retention and separation incentives and also the reasonableness and prudence of the O&M expenses for Campbell Units 1, 2, and 3 retention and separation incentives.

RICHARD T. BLUMENSTOCK
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SECTION I

GENERATION ASSETS

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

A. As of January 2, 2024, the Company's total projected owned generation assets for the 2023/2024 Planning Year had a Generator Verification Test Capacity ("GVTC") of 5,612 MW, comprised of the following units:

TABLE 1

RESOURCE	MICHIGAN LOCATION	IN-SERVICE DATE	RETIREMENT DATE	NET GENERATING CAPABILITY (MW)
COAL FIRED				
JH Campbell 1	West Olive, MI	1962	2025	261
JH Campbell 2	West Olive, MI	1967	2025	356
JH Campbell 3*	West Olive, MI	1980	2025	784 (owned share)
OIL OR GAS FIRED				
Covert	Covert, MI	2004	2040	1089
DE Karn 3	Essexville, MI	1975	2031	594
DE Karn 4	Essexville, MI	1977	2031	606
Zeeland CC	Zeeland, MI	2002	2041	532
Zeeland 1A	Zeeland, MI	2002	2041	159
Zeeland 1B	Zeeland, MI	2002	2041	159
Jackson	Jackson, MI	2002	2041	538
HYDROELECTRIC				
Alcona	Alcona County, MI	1924	n/a	3
Allegan	Allegan County, MI	1936	n/a	1
Cooke	Iosco County, MI	1911	n/a	7
Croton	Newaygo County, MI	1907	n/a	2
Five Channels	Iosco County, MI	1912	n/a	6
Foote	Iosco County, MI	1918	n/a	3
Hardy	Newaygo County, MI	1931	n/a	32
Hodenpyl	Wexford County, MI	1925	n/a	5
Loud	Iosco County, MI	1913	n/a	5
Mio	Oscoda County, MI	1916	n/a	2
Rogers	Mecosta County, MI	1906	n/a	2
Tippy	Manistee County, MI	1918	n/a	6
Webber	Ionia County, MI	1907	n/a	1
RENEWABLES				
Lake Winds	Mason County, MI	2012	2042	101
Cross Winds (Phase I)	Tuscola County, MI	2014	2044	231
Cross Winds (Phase II)	Tuscola County, MI	2018	2048	
Cross Winds (Phase III)	Tuscola County, MI	2018	2048	
Crescent Wind	Jonesville, MI	2021	2051	150
Gratiot Farms Wind	Alma, MI	2021	2051	150
Heartland Farms Wind Park	Ithaca, MI	2024	2054	201
Solar Gardens- GVSU	Grand Rapids, MI	2016	2046	1.6
Solar Gardens- WMU	Kalamazoo, MI	2016	2046	0.6
Cadillac Solar Garden	Cadillac, MI	2021	2051	0.2
Circuit West	Grand Rapids, MI	2019	2049	0.3
ENERGY STORAGE				
Ludington Units 1-6**	Ludington, MI	1973	2069	1169 (owned share)

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1 **Q. What does “owned share” mean when used with respect to Campbell Unit 3?**

2 A. The Company owns approximately 93% of Campbell Unit 3. Michigan Public Power
3 Agency and Wolverine Power Supply Cooperative, Inc. own the remaining 7%. Thus, the
4 784 MW capacity reported is 93% of the Campbell Unit 3 GVTC, reflecting the Company’s
5 share of ownership.

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

8 A. The Company owns 51% of LPS and DTE Electric Company (“DTE”) owns the remaining
9 49%. Thus, the 1,169 MW capacity reported is 51% of the total LPS GVTC, reflecting the
10 Company’s share of ownership.

11 **Q. Do any of the Company’s owned generation units reflect retirement dates which are
12 different from those sponsored in the Company’s previous electric rate case, Case No.
13 U-21389?**

14 A. No. There have been no changes to the retirement dates for the Company’s owned
15 generation units. The only change to the Company’s owned generation units was the
16 addition of Heartland Wind Park which began commercial operation on December 29,
17 2023.

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

20 A. The Settlement Agreement approved in the Company’s 2021 IRP reflects the replacement
21 of the Campbell unit capacity through a number of different resources including continued
22 growth of its solar generation assets, demand response, energy waste reduction, the
23 acquisition of the Covert Plant on June 1, 2023, continued operation of Ludington and Karn

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Units 3 and 4, and the addition of Zonal Resource Credits (“ZRCs”) by June 1, 2025, through a one-time solicitation approved as part of the Settlement Agreement.

The IRP one-time solicitation resulted in the Company’s January 12, 2024, filing of the Tibbits Energy Storage, LLC Power Purchase Agreement (“PPA”), a 100-MW battery storage project which the MPSC approved in its April 11, 2024 Order. The term of the PPA is 20 years, with deliveries expected to commence by May 31, 2025 with an expected PPA termination date of May 31, 2045. The IRP one-time solicitation also resulted in the Company’s May 13, 2024 filing of the Century Oaks Energy Storage LLC PPA, a 200-MW battery storage energy project. The Century Oaks Energy Storage LLC PPA also has a term of 20 years and, with deliveries expected to commence by May 31, 2026, with an expected PPA termination date of May 31, 2046.

GENERATION ASSET STRATEGY

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

A. The Company’s generation asset strategy is focused on providing safe, reliable, regulatory compliant, and economic energy and capacity for its customers. This strategy will be implemented within the construct of the Company’s clean energy goals and its IRPs, as approved by the MPSC.

Q. How does the Company’s generation asset strategy apply to the Company’s various generating units?

A. Consistent with Consumers Energy’s strategy, the Company’s generating asset investments will focus on onboarding renewable energy resources, including BESSs as well as those generating assets that provide the most economic benefit to customers through their energy and capacity value in the respective MISO markets. In addition, the Company will also

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1 ensure it complies with all state and federal regulations. A detailed discussion of River
2 Hydro compliance is discussed in the direct testimony of Company witness Monroe.

3 Consistent with the approval of the Company's Proposed Course of Action
4 ("PCA") in its 2021 IRP, the Company will concentrate investment in new renewable
5 energy resources, and continue investment in the existing gas-fired units as this strategy
6 will provide the greatest long-term customer benefit. The coal-fired Campbell units will
7 have less investment as they approach retirement in 2025. During 2023, the Company's
8 Zeeland and Jackson Plants produced over 41% of the energy value and approximately
9 25% of the capacity value realized by the Company's electric generating fleet (excluding
10 renewables). The addition of the Covert Plant on June 1, 2023 significantly increased the
11 energy and capacity value for the Company's gas-fired generation. During its seven
12 months of operation during 2023, the Covert Plant contributed almost 28% of the total
13 energy value of the Company's electric generating fleet (excluding renewables) and
14 represents over 18% of the generation fleet's capacity value. As such, the Company's
15 investment focus and associated performance projections have been correspondingly set
16 for these generating units. The figures below reflect the 2023 net energy and capacity value
17 by asset type:

FIGURE 1

2023 Net Energy Value

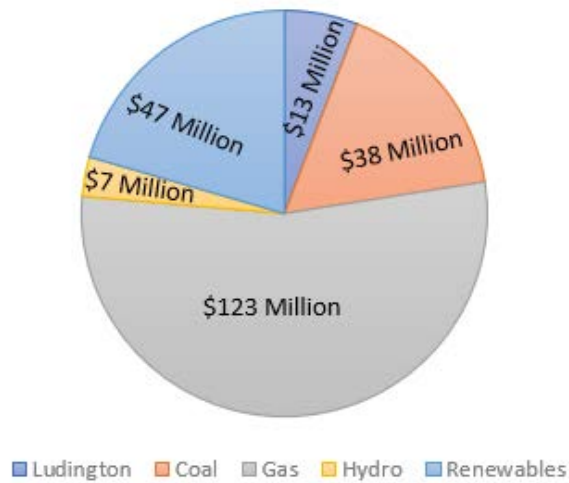
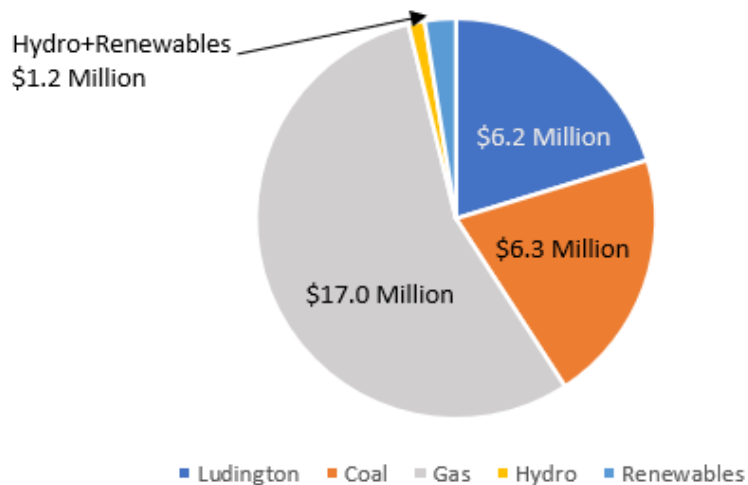


FIGURE 2

Capacity



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

3 **A.** The Company's generation asset strategy with respect to the remaining generating units
4 will vary depending on each unit's energy value, capacity value, and consistency with the
5 Company's currently approved IRP expected retirement dates. The Company will continue

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1 to maintain its generating units, including the River Hydro facilities, to ensure safe and
2 environmentally compliant operations. With the exception of the River Hydro facilities,
3 I will provide additional detail regarding the Company's generation asset strategy for each
4 of the generating units, or group of generating units, in the portion of this direct testimony
5 describing projected generating unit availability. Company witness Monroe will provide
6 additional detail regarding the Company's generation asset strategy for the River Hydro
7 facilities.

8 **Q. Has the Company's existing generation asset strategy changed as a result of the 2023**
9 **Michigan energy legislation?**

10 A. No. While Public Act ("PA") 235 of 2023 requires the Company to achieve a 50%
11 renewable portfolio standard ("RPS") by 2030, the Company had already committed to an
12 aggressive change in its generation asset portfolio mix through its 2018 and 2021 IRPs.
13 Pursuant to PA 235 of 2023, the Company will be filing a renewable energy plan
14 amendment no later than November 15, 2024, which will reflect its plans to comply with
15 the new renewable energy laws.

16 **PERIODIC OUTAGE PLANS, AVAILABILITY, ROR PROJECTIONS,**
17 **AND NET ENERGY VALUE**

18 **Q. Please describe Exhibit A-41 (RTB-1).**

19 A. Exhibit A-41 (RTB-1) identifies the major outages (28 days or longer in duration) that are
20 scheduled during the projected test year ending February 28, 2026, for the Company's
21 fossil-fueled and Ludington Generating Units. The Company's generation asset strategy
22 is a key input to the scheduling of planned outages, and outage duration directly informs
23 the periodic factors ("PFs") reflected on Exhibit A-42 (RTB-2).

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1 **Q. Please describe Exhibit A-42 (RTB-2), Generating Unit Availability Projections.**

2 A. Exhibit A-42 (RTB-2) details Generating Unit Availability Projections for Consumers
3 Energy's coal generation, peaking generation, and hydraulic power generation for the
4 projected test year beginning March 1, 2025 and ending February 28, 2026. Column (a)
5 identifies Consumers Energy's generating units or category of generating units.
6 Column (b) identifies the five-year historical ROR of the generating unit or category of
7 generating unit. Column (c) identifies the projected ROR of the unit or category of
8 generating unit. Column (d) identifies the PF of the generating unit or category of
9 generating unit. Column (e) identifies the projected availability of the generating unit or
10 category of generating unit. Column (f) identifies the five-year historical Net Energy Value
11 ("NEV") of the generating unit or category of generating unit.

12 **Q. Please define ROR.**

13 A. ROR is a measure of the percent of MWh unavailability due to forced or unplanned
14 generating unit outages and forced or unplanned generating unit de-rates.

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

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

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

22 A. The ROR projections for the projected test year ending February 28, 2026 were developed
23 from the five-year (2019-2022) average. These five-year averages were then adjusted to

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1 reflect current operating conditions and projected unit investment. The projected unit
2 investment is developed in accordance with the Company's generation asset strategy.
3 These five-year historical ROR average values are presented in Exhibit A-42 (RTB-2),
4 column (b).

5 **Q. Please define PF.**

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

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

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

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1 **Q. Please define Projected Availability.**

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

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

6 A. The Projected Availability for each generating unit or category of generating unit is
7 calculated as $(100\% - PF) * (100\% - ROR)$. Projected Availability is the key performance
8 metric for implementation of the Company's generation asset strategy for each generating
9 unit or category of generating unit.

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

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

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

18 A. The Company can directly impact Projected Availability for a generating unit by
19 minimizing both PF and ROR for that unit. With respect to minimizing PF, the Company
20 can employ incremental resources during a planned outage to ensure that the critical path
21 for the outage is as short as possible. This strategy could include working 24-hours, seven
22 days a week, for the duration of the outage. Similarly, when a unit experiences an
23 unplanned outage, the Company can employ necessary resources to ensure the unit is

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1 returned to available status as quickly as practical. In addition to minimizing unforced
2 outage length, the Company could invest in a generating unit to increase its reliability and,
3 as a result, decrease the generating unit's projected ROR.

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

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

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

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

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

3 A. The Company utilizes NEV to quantify this customer benefit. At a high level, NEV of a
4 generating unit is the difference between the market value of energy and the cost of
5 producing and supplying that energy. NEV is the net customer benefit of a generator's
6 energy production expressed in dollars. These values are presented in Exhibit A-42
7 (RTB-2), column (f), which identifies five-year (2019-2023) actual NEV amounts.

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

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

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

20 A. Yes. The basis for the Company's generation asset strategy is directly related to this
21 actuality. The Company's investment strategy is focused on those units with the lowest
22 variable production costs to maximize NEV for its customers. As the Company
23 strategically invests additional funds in a generating unit to increase its reliability, the

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1 expectation is for the generating unit's reliability to be higher than otherwise possible
2 absent the investment. Higher reliability, in turn, increases the likelihood the unit is
3 available during periods when market prices exceed the production cost of the unit, thus
4 increasing the NEV of the unit.

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

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

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

11 A. In addition to measuring NEV for a generating unit, the Company also considers the impact
12 a higher availability (specifically ROR) will have on the amount of capacity available from
13 a particular generating unit which receives a monetary credit in the MISO Resource
14 Adequacy Market. Table 2 below summarizes the capacity value of the Company's
15 generating units in the 2023-2024 PRA for Zone 7. Company witness Metz discusses the
16 capacity value of the Company's generating units in the PRA in her testimony in this case.
17 I will discuss the projected impact of the Company's generation asset strategy and
18 associated capital expenditures and major maintenance on the projected availabilities,
19 NEV, and capacity value for each of the generating units later in this direct testimony.

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TABLE 2

RESOURCE	MICHIGAN LOCATION	MISO ISAC ¹ MW	MISO SUMMER SAC ² MW (ZRCs)	CAPACITY VALUE ZONE 7 (SETTLEMENT) ³	CAPACITY VALUE ZONE 7 (75% CONE) ⁴
COAL FIRED					
JH Campbell 1	West Olive, MI	261.3	239.5	\$ 1,311,263	\$ 19,023,796
JH Campbell 2	West Olive, MI	355.5	265.2	\$ 1,451,970	\$ 21,065,181
JH Campbell 3	West Olive, MI	784.3 (owned share)	647.8	\$ 3,546,705	\$ 51,455,596
OIL OR GAS FIRED					
Covert	Covert, MI	1088.6	1028.5	\$ 5,631,038	\$ 81,695,092
DE Karn 3	Essexville, MI	593.5	308.2	\$ 1,687,395	\$ 24,480,727
DE Karn 4	Essexville, MI	606.3	389.3	\$ 2,131,418	\$ 30,922,605
Zeeland CC	Zeeland, MI	532.1	525.3	\$ 2,876,018	\$ 41,725,262
Zeeland 1A	Zeeland, MI	159.4	164.1	\$ 898,448	\$ 13,034,676
Zeeland 1B	Zeeland, MI	158.8	163.5	\$ 895,163	\$ 12,987,018
Jackson	Jackson, MI	537.7	527	\$ 2,885,325	\$ 41,860,295
HYDROELECTRIC					
Alcona	Alcona County, MI	3	3	\$ 16,425	\$ 238,294
Allegan	Allegan County, MI	1.1	1.1	\$ 6,023	\$ 87,374
Cooke	Iosco County, MI	7.1	6.8	\$ 37,230	\$ 540,133
Croton	Newaygo County, MI	2.3	2.3	\$ 12,593	\$ 182,692
Five Channels	Iosco County, MI	6.3	6.1	\$ 33,398	\$ 484,531
Footte	Iosco County, MI	2.9	3	\$ 16,425	\$ 238,294
Hardy	Newaygo County, MI	32.4	31.1	\$ 170,273	\$ 2,470,313
Hodenpyl	Wexford County, MI	4.5	4.5	\$ 24,638	\$ 357,441
Loud	Iosco County, MI	4.9	4.7	\$ 25,733	\$ 373,327
Mio	Oscoda County, MI	1.5	1.6	\$ 8,760	\$ 127,090
Rogers	Mecosta County, MI	2.3	2.4	\$ 13,140	\$ 190,635
Tippy	Manistee County, MI	6.2	6.2	\$ 33,945	\$ 492,474
Webber	Ionia County, MI	1	1	\$ 5,475	\$ 79,431
RENEWABLES					
Lake Winds	Mason County, MI	100.8	14.7	\$ 80,483	\$ 1,167,640
Cross Winds (Phase I, II, III)	Tuscola County, MI	230.6	38.1	\$ 208,598	\$ 3,026,333
Crescent Wind	Jonesville, MI	150	19.2	\$ 105,120	\$ 1,525,081
Gratiot Farms Wind	Alma, MI	150	29.9	\$ 163,703	\$ 2,374,996
Heartland Farms Wind Park	Ithaca, MI	201	36.4	\$ 199,290	\$ 2,891,299
Solar Gardens- GVSU	Grand Rapids, MI	1.6	1.7	\$ 9,308	\$ 135,033
Solar Gardens- WMU	Kalamazoo, MI	0.6	0.6	\$ 3,285	\$ 47,659
Cadillac Solar Garden	Cadillac, MI	0.2	0.2	\$ 1,095	\$ 15,886
Circuit West	Grand Rapids, MI	0.3	0.3	\$ 1,643	\$ 23,829
ENERGY STORAGE					
Ludington Units 1-6	Ludington, MI	1168.8 (owned share)	1138.6	\$ 6,233,835	\$ 90,440,478
¹ ISAC = Intermediate seasonal accredited capacity ² SAC = Seasonal accredited capacity and is converted from ISAC based upon offered availability during RA and non-RA hours ³ 2023-2024 PRA Settlement price of \$15/MW-day for Zone 7. ⁴ 2023-2024 PRA 75% CONE price of \$217.62/MW-day for Zone 7.					

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

A. The strategic plan for Campbell Units 1 and 2 is predicated on their planned retirement on May 31, 2025, as reflected in the Company's 2021 IRP Settlement Agreement. The overall remaining life objective for Campbell Units 1 and 2 is to maintain economic dispatch and capacity value from the customer's perspective. The major maintenance expenses in the plan are targeted to provide safe and regulatory compliant units. Critical reliability investments required to keep the units available will be included in the plan. Projects that are targeted to improve reliability will not be considered.

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

3 A. It is anticipated that the unit performance will degrade from current performance for both
4 Campbell Units 1 and 2, and this risk will be accepted to limit new investment as the units
5 near retirement. Based upon the Campbell Units 1 and 2 major maintenance projects that
6 I will discuss later in this direct testimony, the Company's generation asset strategy is
7 expected to result in an ROR of 16.00% at Campbell Unit 1 and 15.00% at Campbell Unit 2
8 in the test year, as shown on Exhibit A-42 (RTB-2), lines 1 and 2, column (c). During the
9 five-year historical period from 2019 through 2023, Campbell Unit 1 had an ROR of
10 16.89% and Campbell Unit 2 had an ROR of 30.27% as shown on Exhibit A-42 (RTB-2),
11 lines 1 and 2, column (b).

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

14 A. The Projected Availabilities for Campbell Units 1 and 2 in the test year are 28.30% and
15 85.00%, respectively, as shown on Exhibit A-42 (RTB-2), lines 1 and 2, column (e). The
16 Projected Availability for Campbell Unit 1 reflects a projected ROR of 16.00% and a PF
17 of 66.30%, as shown on Exhibit A-42 (RTB-2), line 1, columns (c) and (d). The planned
18 Campbell Unit 1 outage for the test year is scheduled to begin on April 1, 2025 and last for
19 60 days, as reflected on Exhibit A-41 (RTB-1), line 5. Projected Availability for Campbell
20 Unit 2 reflects a projected ROR of 15.00% and a PF of 0.00%, as shown on Exhibit A-42
21 (RTB-2), line 2, columns (c) and (d). No outages are planned at Campbell Unit 2 for the
22 test year ending February 28, 2026.

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1 **Q. How does the availability for Campbell Units 1 and 2 translate into customer value?**

2 A. As reflected on Exhibit A-42 (RTB-2), lines 1 and 2, column (f), during the five-year
3 historical period from 2019 through 2023, Campbell Unit 1 had an NEV of \$94.3 million
4 and Campbell Unit 2 had an NEV of \$83.3 million. The 2023 NEV for each of these units
5 was \$6.0 million and \$2.8 million for Campbell Units 1 and 2, respectively.

6 **Q. Please quantify the capacity value for Campbell Units 1 and 2.**

7 A. As reflected in Table 2, the capacity value based upon the settlement price for Zone 7 in
8 the 2023-2024 PRA is \$1.311 million for Campbell Unit 1 and \$1.452 million for Campbell
9 Unit 2. The hypothetical capacity value upon which the Company plans its capacity
10 resources (75% of Cost of New Entry ("CONE")) for Zone 7 in the 2023-2024 PRA is
11 \$19.0 million for Campbell Unit 1 and \$21.1 million for Campbell Unit 2.

12 **Q. Please provide an overview of the generation asset strategy for Campbell Unit 3.**

13 A. The strategic plan for Campbell Unit 3 is predicated on its planned retirement on May 31,
14 2025 as reflected in the Company's 2021 IRP Settlement Agreement. The overall
15 remaining life objective for Campbell Unit 3 is to maintain economic dispatch and capacity
16 value from the customer's perspective. The major maintenance expenses in the plan are
17 targeted to provide safe and regulatory compliant units. Critical reliability investments
18 required to keep the units available will be included in the plan. Capital projects that are
19 targeted to improve reliability will not be considered.

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

22 A. It is anticipated that unit performance will remain relatively consistent with current
23 performance. Based upon the Campbell Unit 3 capital and major maintenance projects

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discussed later in this testimony, the Company's generation asset strategy is expected to result in an ROR of 8.00% at Campbell Unit 3 in the projected test year, as shown on Exhibit A-42 (RTB-2), line 3, column (c). During the five-year historical period from 2019 through 2023, Campbell Unit 3 had an actual ROR of 14.29%, as shown on Exhibit A-42 (RTB-2), line 3, column (b).

Q. How is this strategy reflected in the Projected Availability for Campbell Unit 3 in the test year?

A. The Projected Availability for Campbell Unit 3 in the test year is 92.00%, as shown on Exhibit A-42 (RTB-2), line 3, column (e). This Availability for Campbell Unit 3 reflects a projected ROR of 8.00% and a PF of 0.00%, as shown on Exhibit A-42 (RTB-2), line 3, columns (c) and (d). No outages are planned at Campbell Unit 3 for the test year ending February 28, 2026.

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

A. As reflected on Exhibit A-42 (RTB-2), line 3, column (f), during the five-year historical period from 2019 through 2023, Campbell Unit 3 had an NEV of \$347.2 million. The 2023 NEV for Campbell Unit 3 was \$29.2 million.

Q. Please quantify the capacity value for Campbell Unit 3.

A. As reflected in Table 2, the Campbell Unit 3 capacity value based upon the settlement price for Zone 7 in the 2023-2024 PRA is \$3.5 million and the Campbell Unit 3 hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2023-2024 PRA is \$51.5 million.

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1 **Q. Please provide an overview of the generation asset strategy for Karn Units 3 and 4.**

2 A. The strategic plan for Karn Units 3 and 4 is predicated on their planned retirement on
3 May 31, 2031 as reflected in the Company's 2021 IRP Settlement Agreement. The overall
4 remaining life objective for Karn Units 3 and 4 is to maintain economic dispatch and
5 capacity value from the customer's perspective. The capital expenditures and major
6 maintenance expenses in the plan are targeted to provide safe and regulatory compliant
7 units. Critical reliability investments required to keep the units available will be included
8 in the plan. Projects that are targeted to improve reliability will not be considered.

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

11 A. It is anticipated that unit performance for Karn Units 3 and 4 will slightly degrade from
12 current performance. Based upon the Karn Units 3 and 4 capital and major maintenance
13 projects that I will discuss later in this direct testimony, the Company's generation asset
14 strategy is expected to result in an ROR of 18.00% at Karn Unit 3 and 18.00% at Karn
15 Unit 4 in the test year, as shown on Exhibit A-42 (RTB-2), lines 4 and 5, column (c).
16 During the five-year historical period from 2019 through 2023, Karn Unit 3 had an ROR
17 of 38.70% and Karn Unit 4 had an ROR of 24.76%, as shown on Exhibit A-42 (RTB-2),
18 lines 4 and 5, column (b).

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

21 A. The projected availabilities for Karn Units 3 and 4 in the test year are 72.34% and 71.44%,
22 respectively, as shown on Exhibit A-42 (RTB-2), lines 4 and 5, column (e). The
23 availability for Karn Unit 3 reflects a projected ROR of 18.00% and a PF of 11.78%, as

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1 shown on Exhibit A-42 (RTB-2), line 4, columns (c) and (d). The planned outage for the
2 test year is scheduled to begin on March 1, 2025 and last for 42 days, as reflected on Exhibit
3 A-41 (RTB-1), line 2. The availability for Karn Unit 4 reflects a projected ROR of 18.00%
4 and a PF of 12.88%, as shown on Exhibit A-42 (RTB-2), line 5, columns (c) and (d). The
5 planned outage for the test year is scheduled to begin on March 22, 2025 and last for
6 46 days, as reflected on Exhibit A-41 (RTB-1), line 4.

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

9 A. As reflected on Exhibit A-42 (RTB-2), lines 4 and 5, column (f), during the five-year
10 historical period from 2019 through 2023, Karn Unit 3 had a NEV of -\$8.1 million and
11 Karn Unit 4 had a NEV of -\$10.4 million. The 2023 NEV for each of these units
12 was -\$1.7 million and -\$0.4 million for Karn Units 3 and 4, respectively.

13 **Q. Please explain why the NEVs for Karn Units 3 and 4 are negative.**

14 A. The NEVs for Karn Units 3 and 4 are negative due to required operation in support of
15 capacity demonstration testing, unit performance validation, and operator training. During
16 this operation, the units are operated as Must-Run resources in the MISO Energy Market
17 and as such, they are price takers. In order to minimize the impact of the required operation
18 of the units, the Company performs those activities during periods in which operation is
19 most economic. However, despite the fact that the NEVs are slightly negative, the units
20 provide a significant amount of capacity value, which far outweighs the negative NEV
21 values. In addition, the Company's ability to have these units dispatched during tight
22 generation days provides reliability benefits for the Company's customers and the MISO
23 energy market.

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1 **Q. Please quantify the capacity value for Karn Units 3 and 4.**

2 A. As reflected in Table 2, the capacity value based upon the settlement price for Zone 7 in
3 the 2023-2024 PRA is \$1.7 million for Karn Unit 3 and \$2.1 million for Karn Unit 4. The
4 hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2023-2024 PRA
5 is \$24.5 million for Karn Unit 3 and \$30.9 million for Karn Unit 4.

6 **Q. Please provide an overview of the generation asset strategy for the Zeeland Plant.**

7 A. The strategic plan for the Zeeland Plant is predicated on plant operation through Planning
8 Year 2040. The overall long-term objective for the Zeeland Plant is to maintain economic
9 dispatch and capacity from the customer's perspective. The units provide significant value
10 to customers in both the energy and resource adequacy markets. The capital expenditures
11 and major maintenance expenses in the plan are targeted to provide a safe, regulatory
12 compliant, and reliable unit. Critical reliability investments required to keep the units
13 available will be included in the plan. Projects that are targeted to improve reliability will
14 be included in the plan if they provide value to customers.

15 **Q. How will the Company's generation asset strategy for the Zeeland Plant impact its**
16 **projected performance?**

17 A. It is anticipated that site performance will remain relatively consistent with current
18 performance. Based upon the Zeeland Plant capital and major maintenance projects that
19 I will discuss later in this testimony, the Company's generation asset strategy is expected
20 to result in an ROR of 4.0% at the Zeeland Plant in the test year, as shown on Exhibit A-42
21 (RTB-2), lines 13 through 15, column (c). During the five-year historical period from 2019
22 through 2023, the Zeeland Plant had ROR values at or below 7.48% for all units, as shown
23 on Exhibit A-42 (RTB-2), lines 13 through 15, column (b).

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

3 A. The Projected Availability for the combined cycle generating units (Units 1 and 2) at the
4 Zeeland Plant in the test year is 83.90%, as shown on Exhibit A-42 (RTB-2), line 13,
5 column (e). The Zeeland Combined Cycle (Units 3, 4, and 5) Generating Unit availability
6 is based upon a projected ROR of 4.0% and a PF of 12.60%, as shown on Exhibit A-42
7 (RTB-2), line 13, columns (c) and (d). The Projected Availabilities for each of the simple
8 cycle generating units at the Zeeland site in the projected test year are 86.79%, as shown
9 on Exhibit A-42 (RTB-2), lines 14 and 15, column (e). Each of the Zeeland simple cycle
10 generating unit Projected Availabilities are based upon projected RORs of 4.0% and PFs
11 of 9.59%, as shown on Exhibit A-42 (RTB-2), lines 14 and 15, columns (c) and (d). There
12 are no outages greater than 28 days scheduled for the Zeeland combined cycle units
13 (Units 3, 4, and 5) in the projected test year ending February 28, 2026, however there are
14 several shorter duration outages of 10 days each scheduled in May and October. The
15 planned outage for the test year for Zeeland Unit 1 is scheduled to begin on March 10, 2025
16 and last for 34 days, as reflected on Exhibit A-41 (RTB-1), line 3. The planned outage for
17 the test year for Zeeland Unit 2 is scheduled to begin on April 21, 2025 and last for 34
18 days, as reflected on Exhibit A-41 (RTB-1), line 6. These outages are scheduled during
19 periods in which energy prices are projected to be lower, thereby reducing the impact of
20 the outages on customers. In addition, the outages are scheduled to maximize future
21 capacity attribution for the units given the MISO seasonal resource adequacy construct.

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1 **Q. How does the Zeeland Plant Projected Availability translate into customer value?**

2 A. As reflected on Exhibit A-42 (RTB-2), lines 13 through 15, column (f), during the five-year
3 historical period from 2019 through 2023, the Zeeland Plant provided a total NEV of
4 \$220.5 million. The 2023 NEV for Zeeland was \$49.4 million.

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

6 A. As reflected in Table 2, the Zeeland Plant capacity value based upon the settlement price
7 for Zone 7 in the 2023-2024 PRA is \$4.7 million and the Zeeland Plant hypothetical
8 capacity value based upon 75% of CONE for Zone 7 in the 2023-2024 PRA is
9 \$67.7 million.

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

11 A. The strategic plan for the Jackson Plant is predicated on plant operation through Planning
12 Year 2040. The overall long-term objective for the Jackson Plant is to maintain economic
13 dispatch and capacity from the customer's perspective. The units provide significant value
14 to customers in both the energy and resource adequacy markets. The capital expenditures
15 and major maintenance expenses in the plan are targeted to provide a safe, regulatory
16 compliant, and reliable unit. Critical reliability investments required to keep the units
17 available will be included in the plan. Projects that are targeted to improve reliability will
18 be included in the plan if they provide value to customers.

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

21 A. It is anticipated that site performance will remain relatively consistent with current
22 performance. Based upon the Jackson Plant capital and major maintenance projects that
23 I will discuss later in this direct testimony, the Company's generation asset strategy is

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1 expected to result in an ROR of 4.50% at the Jackson Plant in the test year, as shown on
2 Exhibit A-42 (RTB-2), line 16, column (c). During the five-year historical period from
3 2019 through 2023, the Jackson Plant had an actual ROR of 8.22%, as shown on Exhibit
4 A-42 (RTB-2), line 16, column (b).

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

7 A. The Projected Availability for all of the generating units at the Jackson site in the test year
8 is 81.63%, as shown on Exhibit A-42 (RTB-2), line 16, column (e). The Projected
9 Availability for the Jackson site reflects a projected ROR of 4.50% and a PF of 14.52%, as
10 shown on Exhibit A-42 (RTB-2), line 16, columns (c) and (d). There are no major planned
11 outages in excess of 28 days for the Jackson units in the test year, however a short 12-day
12 outage is scheduled to begin October 10, 2025. In addition, several derates are scheduled
13 to perform inspections and maintenance on various generating units in April and September
14 2025.

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

16 A. As reflected on Exhibit A-42 (RTB-2), line 16, column (f), during the five-year historical
17 period from 2019 through 2023, the Jackson units provided a total NEV of \$158.4 million.
18 The 2023 NEV for the Jackson Plant was \$24.1 million.

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

20 A. As reflected in Table 2, the Jackson Plant capacity value based upon the settlement price
21 for Zone 7 in the 2023-2024 PRA is \$2.9 million and the Jackson Plant hypothetical
22 capacity value based upon 75% of CONE for Zone 7 in the 2023-2024 PRA is
23 \$41.9 million.

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

3 A. It is anticipated that site performance will remain relatively consistent with past
4 performance under different ownership. Based upon the Covert Plant capital and major
5 maintenance projects that I will discuss later in this direct testimony, the Company's
6 generation asset strategy is expected to result in an ROR of 7.00% for all three units at the
7 Covert Plant in the test year, as shown on Exhibit A-42 (RTB 2), lines 17 through 19,
8 column (c).

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

11 A. The Projected Availability for each of the combined cycle generating units at the Covert
12 Plant in the test year ranges from 75.16% to 82.55%, as shown on Exhibit A-42 (RTB-2),
13 lines 17 through 19, column (e). The Covert Unit 1 unit availability of 80.77% is based
14 upon projected ROR of 7.00% and a PF of 13.15%, as shown on Exhibit A-42 (RTB-2),
15 line 17, columns (c) and (d), the Covert Unit 2 unit availability of 82.55% is based upon
16 projected ROR of 7.00% and a PF of 11.23%, as shown on Exhibit A-42 (RTB-2), line 18,
17 columns (c) and (d), and the Covert Unit 3 unit availability of 75.16% is based upon
18 projected ROR of 7.00% and a PF of 19.18%, as shown on Exhibit A-42 (RTB-2), line 18,
19 columns (c) and (d). The Company will conduct major inspections at all three of the Covert
20 Units during the bridge period/test year. The planned outage for the test year for Covert
21 Unit 1 is scheduled to begin on February 1, 2026 and last for 59 days (beyond the test year),
22 as reflected on Exhibit A-41 (RTB-1), line 8. The planned outage for the test year for
23 Covert Unit 2 is scheduled to begin on February 1, 2025 and last for 59 days, as reflected

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1 on Exhibit A-41 (RTB-1), line 1. The planned outage for the test year for Covert Unit 3 is
2 scheduled to begin on November 1, 2025 and last for 59 days, as reflected on Exhibit A-41
3 (RTB-1), line 7. These outages are scheduled for periods in which energy prices are
4 projected to be lower, thereby reducing the impact of the outages on customers. In addition,
5 the outages are scheduled to maximize future capacity attribution for the units given the
6 MISO seasonal resource adequacy construct.

7 **Q. How does the Covert Plant Projected Availability translate into customer value?**

8 A. As reflected on Exhibit A-42 (RTB-2), lines 17 through 19, column (f), during the
9 seven-month historical period in 2023, the Covert units provided a total NEV of
10 \$49.4 million.

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

12 A. As reflected in Table 2, the Covert Plant capacity value based upon the settlement price for
13 Zone 7 in the 2023-2024 PRA is \$5.6 million and the Covert Plant hypothetical capacity
14 value based upon 75% of CONE for Zone 7 in the 2023-2024 PRA is \$81.7 million.

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

16 A. A full discussion of the Company's River Hydro generation asset strategy is included in
17 the direct testimony of Company witness Monroe. In addition, Company witness Monroe
18 will discuss the capital investments for the River Hydro projects which are necessary for
19 continued safe and reliable operation. Regardless of the future of the River Hydro
20 facilities, Consumers Energy will maintain safe operation of its hydroelectric dams as long
21 as they are licensed by the Company. As all of the River Hydro facilities are currently
22 licensed through at least 2034, the Company needs to continue to invest in these assets to

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maintain its licenses and the Company's commitment to dam safety as long as the Company holds the Federal Energy Regulatory Commission ("FERC") licenses.

Q. Did the Order in the Company's 2023 Electric Rate Case (Case No. U-21389) establish any specific requirements for the River Hydro facilities?

A. Yes. Paragraph D on page 309 of the March 1, 2024 Order in Case No. U-21389 required the following:

"If cost recovery for work on the Hardy Dam is sought in its next general electric rate case, Consumers Energy Company shall file a full evaluation of all alternative options and pricing for the work that must be done in order to remain in compliance with Federal Energy Regulatory Commission standards, with projected total costs."

As reflected in Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, line 27, the Company intends to invest \$53.854 million in the Hardy Dam Auxiliary Spillway Project in the projected test year with construction beginning in the fall of 2025. Company witness Monroe is supporting the full evaluation of the alternative options for the Hardy Dam in order to remain in Compliance with FERC requirements and its operating license.

Q. What is the status of the requirements included in the Settlement Agreement in the Company's 2022 Electric Rate Case (Case No. U-21224) for the Muskegon River?

A. The Company has fulfilled the requirements reflected in the Settlement Agreement in the Company's 2022 Electric Rate Case (Case No. U-21224). The Settlement Agreement reached in Case No. U-21224 required the Company to "work with Staff and the Attorney General to scope and conduct the following analyses of all reasonable options prior to commencing construction of the Hardy Dam upgrades:

"a. Economic business cases performed by an outside engineering firm with experience in dam engineering, construction, and decommissioning, that will compare the

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1 projected capital and O&M costs through the end of Hardy
2 Dam's current Federal Energy Regulatory Commission
3 ("FERC") license term, with the value of the energy and
4 capacity that Hardy Dam will provide customers, under a
5 variety of reasonable assumptions. These assumptions will
6 be inclusive of at least the current long-term forecast for
7 energy prices and replacement capacity priced at a range of
8 percentages of the Cost of New Entry. The business case
9 shall utilize best available assumptions and consider, at a
10 minimum, the feasibility and impacts of (i) divestiture, (ii)
11 permanently lowering the reservoir height, (iii) full
12 decommissioning and removal, and (iv) other options that
13 avoid or minimize the impact of the Hardy Dam on customer
14 rates. In addition, the Company will perform, or cause to be
15 performed, an economic assessment of the impact of each of
16 these scenarios on the Muskegon River Hydroelectric Dam
17 communities.

18 b. The Company shall engage in discussions with affected
19 local communities on the costs and timing of the proposed
20 Muskegon River Hydroelectric Dam projects, the need for
21 additional funding from those Muskegon River
22 Hydroelectric Dam impacted communities and possible
23 mechanisms for funding to ensure FERC compliance and
24 dam safety at the Hardy Dam, and the impact to the Hardy
25 Dam and reservoir (as well as the Rogers and Croton dams
26 and reservoirs) if this additional funding is not already
27 recovered in Consumers Energy rates or received from other
28 sources. Prior to construction of the Hardy Dam upgrades,
29 the Company agrees to report on these discussions and
30 inform the Commission whether additional funding from the
31 communities or other sources is feasible (both as to amounts
32 and timing) and provide a best-efforts estimate of the total
33 revenue, if any, that could potentially be available from such
34 sources."

35 **Q. What is the status of the Company's progress on the business cases?**

36 A. Consistent with the terms of the Settlement Agreement, the Company has commissioned
37 the performance of business cases for the Muskegon River Hydro facilities (Croton, Hardy
38 and Rogers) by an outside engineering firm that has experience in dam engineering,
39 construction, and decommissioning. The business cases utilized best available assumptions

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1 and considered divestiture (as will be discussed later in this direct testimony), full
2 decommissioning and removal utilizing all three decommissioning options, and a
3 permanent lowering of the reservoir height. **Confidential** Exhibit A-149 (AJM-7) includes
4 the results of the business cases for the Muskegon River Hydro facilities.

5 In addition, the Company commissioned the performance of an economic
6 assessment of the impact of each of these scenarios on the Muskegon River Hydro facilities
7 communities. The results of these economic assessments are presented in Exhibit A-44
8 (RTB-5).

9 **Q. Did the Company engage the MPSC Staff and the Attorney General in the**
10 **development of the business cases and the economic assessments?**

11 A. Yes. The Company met regularly with the MPSC Staff and the Attorney General to review
12 the scope and receive input on both the business cases and the economic assessments.
13 Through a non-disclosure agreement (“NDA”), the Company shared all relevant
14 information related to each of the scope items, met to both present and discuss the inputs,
15 scope, and results of each of the analyses. The Company provided formal responses to
16 interrogatories regarding the process, data, and the results, facilitated a tour of Hardy Dam
17 for the Attorney General, and also facilitated specific discussions on topics such as
18 probable maximum flood (“PMF”) to ensure understanding of the Hardy project design
19 was as complete as possible.

20 **Q. What is the status of the RFP for River Hydro divestiture?**

21 A. The Company launched an RFP to identify potential buyers for its 13 River Hydro facilities
22 on February 15, 2024. The RFP participants will move through a two-stage evaluation and
23 bidding process that is expected to be complete by the end of 2024.

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1 **Q. Has the Company received responses from the February 15, 2024 RFP?**

2 A. Yes. As part of the first phase of the RFP, which involves bidder screening based on,
3 among other things, qualifications and indicative pricing, the Company received responses
4 to the RFP on March 15, 2024. The Company has evaluated the bids and moved to the
5 second phase of the RFP in April of 2024.

6 **Q. What is the scope of Phase 2 of the RFP process?**

7 A. Phase 2 involves engaging with seven selected entities in due diligence, negotiations, and
8 potential sale agreement(s). Due diligence will be completed during the summer, and
9 negotiations will take place for the remainder of the year.

10 **Q. What is the status of the Company's discussions with affected local communities and**
11 **their ability to provide funding to maintain the River Hydros?**

12 A. To identify the potential for community funding, the Company met with local elected
13 officials and other key community stakeholders (chamber of commerce, economic
14 development, homeowners associations, parks department, etc.) at each River Hydro
15 facility. The Company met several times with each community, the first meeting was to
16 introduce the concept of community funding to the community and gauge their interest and
17 initial thoughts on capacity. If favorable, we asked them to spend some time researching
18 the initial options we discussed to better understand their potential capacity for funding.

19 The Company revisited each community four-to-six weeks later to discuss those
20 options and truly understand the community's capacity to support its operations. At the
21 second meeting the Company did not ask for any commitments. As a result of the meetings,
22 the Company did identify some funding in most communities, but the available funding

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1 was not significant when compared to the Company's current gap between relicensing and
2 decommissioning cost estimates.

3 **Q. What are your thoughts regarding the Company's compliance with the requirements**
4 **of the Settlement Agreement?**

5 A. As a result of the Company's collaboration with the MPSC Staff and the Attorney General,
6 its commissioning of business cases and economic impact studies, and its economic
7 outreach and identification of external funding, it is my opinion that the Company has
8 satisfied the requirements of the Settlement Agreement.

9 **Q. Has the MPSC imposed additional requirements on the Company before moving**
10 **forward with construction on the Hardy Dam?**

11 A. Yes. The March 1, 2024 Order in the Company's 2023 Electric Rate Case (Case No.
12 U-21389) included the following requirement in ordering paragraph D:

13 "If cost recovery for work on the Hardy Dam is sought in its
14 next general electric rate case, Consumers Energy Company
15 shall file a full evaluation of all alternative options and
16 pricing for the work that must be done in order to remain in
17 compliance with Federal Energy Regulatory Commission
18 standards, with projected total costs."

19 Company witness Monroe addresses this requirement in his direct testimony as the
20 Company has included projected project costs for work on the Hardy Dam in this
21 proceeding.

22 **Q. Please describe the Company's anticipated timeline for deciding whether each River**
23 **Hydro will be relicensed, sold, or decommissioned.**

24 A. The Company intends to make a decision on the divestiture of the River Hydros by the end
25 of 2024. Should the Company make a decision to not divest the assets, the Company

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1 would revisit the decision to relicense or decommission the River Hydros, with the
2 intention of making a decision in the 1st quarter of 2025.

3 **Q. Will the Company's decision affect the need for the River Hydro investments and**
4 **expenses requested in this case?**

5 A. No. Regardless of the ultimate decision on whether to relicense, sell, or decommission the
6 respective River Hydro facilities, the investments and expenses requested in this case are
7 needed to appropriately maintain those facilities in order to ensure they are safe and legally
8 compliant. The required diligence which needs to be undertaken in order to make a decision
9 on the future of the River Hydros (e.g., adequate evaluation of the bids submitted by the
10 seven entities which are part of Phase 2 of the RFP process and analysis of the community
11 impact study) means that a decision on the future of the River Hydros cannot be reasonably
12 made until late 2024 at the earliest. Subsequent activities to implement the decision(s) will
13 extend into and beyond the test year for this case. The River Hydro investments and
14 expenses requested in this case are needed to reasonably operate those facilities regardless
15 of the ultimate decision on whether to relicense, decommission, or sell one or more of
16 them.

17 **Q. Would it be reasonable to delay approval of the River Hydro investments and**
18 **expenses requested in this case?**

19 A. No, it would not. Delaying approval of the River Hydro cost recovery in this case would
20 mean denying the Company's ability to execute the investments and operations and

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1 maintenance activities necessary to keep the River Hydro facilities safe and compliant with
2 FERC regulations.

3 **Q. Please provide an overview of the generation asset strategy for Ludington.**

4 A. The strategic plan for Ludington is predicated on retiring the units by July 30, 2069. The
5 Ludington units recently underwent a major overhaul that was intended to provide
6 increased capacity and generation, increased efficiency, reduced maintenance, and an
7 extended service life which supported the 50-year FERC license extension granted in 2019.
8 Ludington is a FERC-regulated hydroelectric facility for which dam safety investments are
9 identified and initiated as a result of regulatory compliance and adherence to FERC
10 processes, including the FERC Part 12 process discussed in Mr. Monroe's direct testimony.

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

13 A. Based upon the Ludington capital and major maintenance projects that I will discuss later
14 in this direct testimony, the Company's generation asset strategy is expected to result in an
15 ROR of 3.50% for the Ludington units in the test year, as shown on Exhibit A-42 (RTB-2),
16 lines 6 through 11, column (c). During the five-year historical period from 2019 through
17 2023, the Ludington units had average ROR values ranging from 4.94% to 7.75%, as
18 shown on Exhibit A-42 (RTB-2), lines 6 through 11, column (b).

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

21 A. Given the intermittent nature of solar and wind generation and the Company's plans to
22 move to a zero net carbon future, Ludington is becoming a more critical component of the
23 Company's generation portfolio since it can deliver a significant amount of energy in a

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1 short time period; providing energy supply from the reservoir during periods when the
2 wind doesn't blow and/or the sun doesn't shine. Additionally, when there is an
3 over-abundance of wind and/or solar generation, Ludington can utilize the excess energy
4 to fill the reservoir. Ludington's large energy storage capability greatly enables the
5 transition to renewable energy. However, defective and non-confirming work performed
6 by Toshiba during recent overhaul efforts must be resolved to ensure Ludington can fully
7 provide these intended benefits over its remaining life.

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

10 A. The Projected Availabilities for all of the Ludington units in the projected test year ranges
11 from 74.03% to 88.30%, as shown on Exhibit A-42 (RTB-2), lines 6 through 11,
12 column (e). The Projected Availabilities for the Ludington generating units reflect a
13 projected ROR of 3.50% and PFs ranging from 8.49% to 23.29%, as shown on Exhibit
14 A-42 (RTB-2), lines 6 through 11, columns (c) and (d). There are currently no major
15 outages planned for the Ludington units in the test year; shorter outages on all six
16 Ludington units are scheduled throughout the test period, primarily in the spring and fall.
17 These outages will be used, in part, to evaluate and monitor ongoing issues with the
18 Toshiba work. The outages are scheduled during periods in which the likelihood of
19 Ludington unit dispatch is lower, thereby reducing the impact of the outages on customers.

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

22 A. The Company's strategic plan for Renewable Energy Assets, both wind and solar, has been
23 entirely driven by the Company's MPSC-approved 2021 IRP Settlement Agreement.

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1 Consistent with the IRP, the strategy for the wind assets is to complete construction and
2 have all wind assets in service in 2024 with the completion of Heartland Wind Farm. With
3 respect to solar, the Company plans to continue to add incremental solar resources in
4 accordance with its Clean Energy Plan and Renewable Energy Plan. These solar resources
5 are being added pursuant to the Company's 2018 IRP and 2021 IRP annual solicitations,
6 as discussed in more detail later in this direct testimony. In addition, the Company
7 anticipates that it will also add up to 1,000 MW of wind and solar assets through 2027¹ in
8 support of the Company's Voluntary Green Pricing Program, and their costs will be
9 reconciled through the Company's Renewable Energy Plan. The overall investment
10 objective for the Company-owned assets is to provide funding for projects as appropriate
11 to maintain economic dispatch and capacity from the customer's perspective. The
12 Company has a time-based availability target of 97% for its renewable energy wind assets.
13 This availability target considers those periods during which the wind is sufficient to
14 produce energy. The capital expenditures and major maintenance expenses in the plan are
15 targeted to maintain the designed performance level.

16 **Q. How will the enactment of PA 235 of 2023 impact the Company's renewable energy**
17 **portfolio?**

18 A. As previously discussed in this direct testimony, the Company will be filing a Renewable
19 Energy Plan Amendment no later than November 15, 2024. PA 235 of 2023 has
20 established both renewable and clean energy targets for the future beginning with a
21 renewable energy compliance target of 50% in 2030. The newly passed law became

¹ The Settlement Agreement in the Company's 2021 Renewable Energy Plan Amendment, Case No. U-20984, reflected the addition of up to 500 MW of solar and 500 MW of wind over the period from 2024 through 2027 to support the Company's Large Customer Renewable Energy Program.

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effective on February 27, 2024 and provides for the utilization of renewable energy assets from anywhere within the MISO footprint.

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

A. Similar to the Company's River Hydro units, the production cost of the Company's renewable energy assets is zero. As such, all energy sold into the MISO energy market has value provided that the MISO locational marginal prices are positive. Additionally, renewable assets provide the Company's customers with renewable energy credits. As reflected on Exhibit A-42 (RTB-2), lines 20 through 21, column (f), during the five-year historical period from 2019 through 2023, the Cross Winds Energy Park and the Lake Winds Energy Park provided a total NEV of \$166.7 million. The 2023 NEVs for Cross Winds Energy Park and Lake Winds Energy Park were \$18.6 million and \$7.0 million, respectively. As reflected on Exhibit A-42 (RTB-2), lines 22 through 23, column (f), during the two-year historical period from 2022 through 2023, Gratiot Farms Wind and Crescent Wind were provided total NEV of \$68.5 million. The 2023 NEVs for Gratiot Farms Wind and Crescent Wind were \$9.7 million and \$10.7 million, respectively. Heartland Farms Wind Park began commercial operation on January 2, 2024, and as reflected on Exhibit A-42 (RTB-2), line 24, column (f), generated \$0.4 million in NEV in 2023 following its December 29, 2023 commercial operation date. The Company began to measure the NEV for its solar assets in 2020 and the 2020 through 2023 NEV for its Solar Garden Assets totaled \$1,140,655.

Q. Please quantify the capacity value for renewable energy assets.

A. As reflected in Table 2, the renewable asset capacity value based upon the settlement price for Zone 7 in the 2023-2024 PRA is \$0.8 million and the renewable asset hypothetical

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capacity value based upon 75% of CONE for Zone 7 in the 2023-2024 PRA is \$11.2 million.

Q. Why have you included a hypothetical capacity value for each of the generating units or category of generating units?

A. I have included these hypothetical values to reflect the capacity values that the Company uses in its capacity planning process. Company witness Metz provides additional information regarding the capacity value of the Company's generation assets in MISO's PRA as well as the projected capacity margin in future years for Zone 7.

Q. How will the Company determine the reasonableness and prudence of additional investments in the electric generating fleet?

A. Additional investment in the remaining units over and above those necessary to maintain safety and regulatory compliance would require some level of economic benefit for customers, otherwise the investment does not make sense. The generating unit periodic outage plans, projected RORs and, ultimately, projected availability for each generating unit or category of generating units reflects the Company's generation asset strategy.

SECTION II
ENVIRONMENTAL REGULATIONS
OVERVIEW

Q. Can you please list the environmental regulations with which Consumers Energy is required to comply and that are relevant to expenditures for which the Company is seeking recovery in this case?

A. Yes. The Company's fossil-fueled Electric Generating Units ("EGUs") are subject to numerous complex and overlapping air, water, and waste regulations.

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Current (On-going) Environmental Compliance

Environmental Regulations – Air Quality

Q. Describe Consumers Energy’s Existing Air Quality Compliance Strategy (“AQCS”).

A. Over the past decade, Consumers Energy has had expenditures to comply with a variety of air quality-related regulations, including the Cross State Air Pollution Rule, the Mercury and Air Toxics Standards, and the Michigan Mercury Rule, among others. The background and purpose of each such rule has been discussed in the testimony of prior rate cases, including Case No. U-17735. To comply with these regulations, Consumers Energy created the AQCS. Cost recovery reflecting the Company’s AQCS was approved in the November 19, 2015 Order in the Company’s 2014 Electric Rate Case (Case No. U-17735). This AQCS has prudently ensured compliance with applicable state and federal air-quality related regulations. The Company’s actions and investments to achieve such compliance have been performed in a manner which has minimized, to the extent reasonably possible, the associated costs for customers. The investments made to ensure environmental compliance have allowed the continued operation of coal generation while the Company transitions to carbon-free generation sources like solar.

Q. Are there any updates to the air quality-related regulations for which the Company’s existing AQCS complies?

A. Yes. In April 2022 the Environmental Protection Agency (“EPA”) proposed the “Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard.” The EPA’s rule was finalized, effective March 15, 2023. The rule resulted in very little impact to the Company in the short term. The rule does contain a budget re-allocation provision which will ratchet down the nitrogen oxide

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1 (“NOx”) allowances allocated to the Company, so the Company will continue to monitor
2 the rule and evaluate the various options for compliance.

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

5 A. Any capital and/or O&M required for the operation of the air quality control systems that
6 the Company is seeking recovery can be found in Exhibits A-12 (RTB-3), Schedule B-5.2
7 and A-43 (RTB-4).

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

10 A. No, not at this time. The EPA released proposed greenhouse gas (“GHG”) regulations for
11 power plants under Section 111 of the Clean Air Act in May 2023. The proposed
12 regulation covered GHG emissions from existing coal-fired and some existing natural
13 gas-fired units. The rule does not impact the Company’s remaining coal-fired units due to
14 the May 2025 retirement date for all coal-fired units. The EPA announced in March 2024
15 that when the proposed Section 111 rule is finalized, scheduled for April 2024, it will no
16 longer cover existing natural-gas fired units. EPA states that existing natural-gas fired
17 units will be covered in a future regulation.

18 **Environmental Regulations and Compliance Strategy – Waste**

19 **Q. Can you please describe the relevant parts of the Resource Conservation and**
20 **Recovery Act (“RCRA”) as related to Coal Combustion Residuals (“CCR”)**
21 **management?**

22 A. On April 17, 2015, the EPA published 40 CFR Parts 257 and 261, Disposal of CCRs from
23 Electric Utilities, in the Federal Register under Subtitle D of the RCRA. The rules establish

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1 minimum national criteria for purposes of determining which CCR solid waste disposal
2 facilities and solid waste management practices pose a reasonable probability of adverse
3 effect on health or the environment under RCRA. The rule is considered
4 self-implementing, meaning that affected facilities must certify compliance with the
5 published standards and schedules. By codifying standards under Subtitle D, Owners and
6 Operators are not required to obtain permits, and states are not required to adopt and
7 implement the new rules. Instead, the rules' only enforcement mechanism is for a state or
8 citizen group to bring a RCRA citizen suit in federal district court against any facility that
9 is alleged to be in noncompliance with the newly promulgated minimum standards. In
10 December 2016, the Water Infrastructure Improvements for the Nation ("WIIN") Act was
11 passed. This bill provides authority for state implementation of coal ash management
12 through a state permit program in lieu of the current enforcement of the CCR Rule through
13 the RCRA citizen-suit authority. States may elect to submit a CCR permit program to the
14 EPA for approval. The State of Michigan revised its solid waste statute in late 2018 to
15 outline a state CCR permitting program. Michigan has submitted its application to the EPA
16 for a permit program and is awaiting the EPAs review of administrative completeness. In
17 the interim, the EPA has enforcement authority over the RCRA-CCR Rule as provided in
18 the WIIN Act.

19 The existence of a state permitting program allows Department of Environment,
20 Great Lakes, and Energy ("EGLE") to issue permits under Michigan's solid waste
21 management statute (Part 115 of the Natural Resources and Protection Act of 1994
22 ("NREPA"), as amended) to regulate compliance schedules and activities for CCR landfills
23 and surface impoundments. Although the current state CCR permitting program was

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1 passed into law and Consumers Energy is obligated to comply with the associated statute,
2 permits, and licenses, the program must be approved by the EPA on the basis that it is “as
3 protective as” the CCR Rule to avoid dual state and federal regulation. Thus, similar
4 compliance standards are required within the state permitting program, including
5 requirements to make compliance documentation publicly available, completing the work,
6 and then self-reporting by providing notifications to EGLE and posting to a publicly
7 accessible compliance website.

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

11 A. The Company’s CCR management compliance strategy was approved in Case No.
12 U-18322. The major capital work for compliance has been completed. The Cost of
13 Removal (“COR”) and/or O&M required for the management of CCRs under the RCRA
14 that the Company is seeking recovery of can be found in Exhibits A-122 (JJK-3) and A-42
15 (RTB-4). The COR expenses represent historical expenses only. Separately, there are
16 closure activities that will continue throughout the bridge period and test year and beyond;
17 however, those expenses are COR and are not included in this filing.

18 **SECTION III**
19 **GENERATION CAPITAL EXPENDITURES**
20 **OVERVIEW**

21 **Q. What factors does the Company consider in determining the capital investments that**
22 **it will make at its generating plants?**

23 A. The major drivers in the determination of generation capital investments are plant safety,
24 compliance with regulations, and reliability. Consumers Energy’s strategy for complying
25 with environmental regulations was previously discussed in this direct testimony.

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1 **Q. Please describe Exhibit A-12 (RTB-3), Schedule B-5.2, Generation Capital**
2 **Expenditures.**

3 A. This exhibit presents the capital expenditures for Generation, 2023 through the projected
4 test year - 12 months ending February 28, 2026. Exhibit A-12 (RTB-3), Schedule B-5.2,
5 is a nine-page exhibit. Page 1 of this exhibit presents a summary of Generation capital
6 expenditures for the Historical Period ended December 31, 2023, the Projected 14-month
7 Bridge Period beginning January 1, 2024 and ending February 28, 2025, and the projected
8 test year beginning March 1, 2025 and ending February 28, 2026. This summary
9 information is broken down by Steam Power Generation, Hydraulic Power Generation,
10 Pumped Storage Generation, and Other Production Plant. Pages 2 through 5 of this exhibit
11 capture the same Historical Year, Bridge Period, and Test Year Generation capital
12 expenditures information, but is presented by generating sites and environmental
13 categories. This information is further detailed by Contractor, Labor, Materials, Business
14 Expenses, Contingency, and Other. Page 6 of this exhibit represents a summary of pages 2
15 through 5 of this exhibit. Finally, pages 7 through 9 of this exhibit identify the capital
16 projects and associated expenditures that are greater than \$1 million that contribute to the
17 overall capital expenditures summarized on pages 1 through 6 of this exhibit. Specifically,
18 page 7 of this exhibit presents capital projects for the Historical Period ended December 31,
19 2023; page 8 of this exhibit presents capital projects for the Projected 14-month Bridge
20 Period beginning January 1, 2024 and ending February 28, 2025; and page 9 of this exhibit
21 presents capital projects for the projected test year ending February 28, 2026.

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1 **Q. What project information is presented on Exhibit A-12 (RTB-3), Schedule B-5.2,**
2 **pages 7 through 9?**

3 A. Exhibit A-12 (RTB-3), Schedule B-5.2, pages 7 through 9, presents the generation type,
4 the generation unit, project type, project classification, project description, and project cost
5 information. The project type identifies whether the project is routine or non-routine.
6 Routine projects include work that is performed regularly; whereas, non-routine projects
7 are typically undertaken once every 10 years or longer. The budget approval reflects the
8 status of internal approval for the project, including projected cost amount. Exhibit A-12
9 (RTB-3), Schedule B-5.2, page 7, includes both projected and actual capital project cost;
10 whereas, Exhibit A-12 (RTB-3), Schedule B-5.2, pages 8 and 9, includes only the project
11 projected amount.

12 **Q. What level of capital spending for generating plants does the Company request the**
13 **Commission to incorporate into rates in this case?**

14 A. The Company's rate relief request in this case reflects capital spending on projects for its
15 generating plants of \$859.095 million for the historical test year ended December 31, 2023
16 as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 1, line 17, column (b);
17 \$463.548 million in the projected 14-month Bridge Period ending February 28, 2025 as
18 shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 1, line 17, column (e); and
19 \$600.484 million in the projected test year ending February 28, 2026 as shown on Exhibit
20 A-12 (RTB-3), Schedule B-5.2, page 1, line 17, column (f).

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

23 A. No. The Company no longer includes contingency in its generation projects.

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

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

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

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

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

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

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

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

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

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

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

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

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

7 A. The cause of each of the historical events impacting availability are evaluated and
8 measured, and the actions necessary to avoid the same or similar events are considered for
9 implementation. In many cases, actions necessary to prevent the event from recurring are
10 cost beneficial. The availability projections, including ROR, simply reflect the Company's
11 best estimate of the operational benefits of those corrective actions that have already been
12 taken or are planned to be taken, through the projected test year ending February 28, 2026.

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

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

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

19 A. Yes. The Company often forecasts future actions and capital expenditures based on
20 currently available information, many months before the work is completed. To provide
21 some perspective, the outage schedule used in this case was approved in August 2023.
22 A review of the outage schedule used in this case identifies eight scheduled outages that
23 begin in March 2025 (18 months after the schedule was approved) and run through

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1 February 28, 2026, 29 months later. During each of these eight scheduled outages,
2 Consumers Energy has scheduled a number of tasks to be performed. Because of the long
3 lead times, the number of outages scheduled during the test year, and the fact that several
4 different tasks will be performed during each outage, it is inevitable that some scheduled
5 outages and forecast capital expenditures will change. However, the Company has a
6 history of prudent capital investments in its generating facilities, which have been
7 consistently supported by the Commission.

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

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

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

13 A. Yes. The Company's fall 2023 outage for Campbell Unit 1 was originally scheduled from
14 October 13, 2023 through November 12, 2023. The unit was placed into economic reserve
15 status on February 19, 2023 and subsequently began a maintenance outage on March 7,
16 2023. The maintenance outage lasted for 14 days, ending on March 21, 2023. During this
17 timeframe, all priority work scope that was scheduled for the fall outage was completed,
18 obviating the need for the planned outage scheduled to begin on October 13, 2023.

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

21 A. Consistent with the Company's generation asset strategy, generation projected capital
22 investments support the continued safe, regulatory compliant, and reliable operations of
23 the Company's electric generating fleet. Projected capital investments are informed by

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1 historical and anticipated performance of the units. The reasonableness of the generation
2 capital investments is indicated by the sustained or improved performance of the
3 Company's electric generating fleet relative to: (1) the safety of the employees, contractors,
4 and community at and around the generating facilities; (2) compliance with rules and
5 regulations; and (3) reliably participating in the energy, resource adequacy, and ancillary
6 services markets.

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

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

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

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

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1 **Q. How are PIDs related to Concept Approval Documents (“CADs”)?**

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

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

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

13 **2023 HISTORICAL TEST YEAR CAPITAL EXPENDITURES**

14 **Q. How does the 2023 actual capital expenditure amount of \$859.095 million compare to**
15 **the amount of capital expenditures reflected in the Company’s request in Case No.**
16 **U-21389?**

17 A. The 2023 actual capital expenditure amount of \$859.095 million is \$430.277 million below
18 the Company’s requested amount in Case No. U-21389. The reduction in the Company’s
19 actual capital expenditure amount is directly attributable to the removal of the capital
20 expenditures for IRP solar projects and the actual accounting treatment of the Covert
21 purchase. While the Covert total purchase cost was consistent with projections, the total
22 amount was not recorded as an addition to plant in service. The actual amount recorded as
23 capital was \$151.858 million less than the projected purchase amount as can be seen on

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1 Exhibit A-12 (RTB-3), Schedule B-5.2, page 7, line 3, columns (g) and (h). The projected
2 amounts for the 2019 and 2020 IRP Solar Bid Events totaled \$355.250 million in the
3 Company's 2023 Electric Rate Case No. U-21389 (see Exhibit A-12 (RTB-3), Schedule
4 B-5.1, page 9, lines 38 and 39, column (n)), however these amounts were removed from
5 the case due to their project status. The projected solar project capital expenditures were
6 not projected to close by the end of the projected test year and were offset by the allowance
7 for funds used during construction ("AFUDC"). As such, the underspend did not impact
8 the revenue requirement. A compilation of the 2023 projects which have actual capital
9 expenditure amounts greater than \$1 million is presented on Exhibit A-12 (RTB-3),
10 Schedule B-5.2, page 7.

11 **Q. How does the compilation of capital projects on Exhibit A-12 (RTB-3), Schedule**
12 **B-5.2, page 7, compare with the 2023 capital projects reflected on Case No. U-21389,**
13 **Exhibit A-12 (RTB-3), Schedule B-5.1, page 9?**

14 A. A comparison of the projects on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7, with the
15 2023 projects reflected on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1,
16 page 9, reveals that there are seven projects on Exhibit A-12 (RTB-3), Schedule B-5.2,
17 page 7, which were not reflected on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule
18 B-5.1, page 9. In addition, there were twenty projects for 2023 that were reflected on Case
19 No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, that are not presented on
20 Exhibit A-12 (RTB-3), Schedule B-5.2, page 7.

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Q. Please discuss the 2023 capital projects that were included on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, that are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7.

A. The following projects are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7, due to the fact that their actual 2023 capital expenditure amount was less than \$1 million, the project was disallowed, reduced in cost, or not pursued in 2023. The disposition of these capital projects is provided below:

Below is a list of projects whose projected bridge period costs were disallowed in the final order in Case No. U-21389:

Project Description	Projected Amount
Covert Non LTSA Capital - Extras not included in contract	\$ 3,942,510
Karn Tank Farm Storage Tank Heating Line Replacement	\$ 1,253,971
Karn Sync Wire Replacement	\$ 1,450,000
Alcona Core Wall Remediation Project	\$ 1,810,370
Rogers Probable Maximum Flood Project	\$ 1,898,708
2019 Solar Bid Event – Mustang Mile	\$ 233,064,275
2020 Solar Bid Event – Washtenaw	\$ 122,186,164

Below is a list of projects whose projected bridge period costs were reduced or deferred by the Company and their projected amounts approved in the final order in Case No. U-21389 were less than \$1 million:

Project Description	Projected Amount	Project Reduction
Webber Unit 1 Generator Rewind	\$ 1,020,000	\$ 1,020,000
Zeeland Milestone Outage Capital to GE - Part of LTSA Contract	\$ 7,870,000	\$ 7,870,000
Zeeland Unit 4 Field Rewind of Generator Rotor	\$ 1,205,357	\$ 1,205,357
Zeeland Unit 3 Field Rewind of Generator Rotor	\$ 1,205,357	\$ 1,205,357
Cooke Spillway Hoist Replacement	\$ 2,100,000	\$ 1,492,000
Zeeland Phase 2 599 699 345kV Breaker Replacement	\$ 1,222,915	\$ 773,000
Ludington Oil Water Separator Replacement	\$ 1,162,917	\$ 679,000
Ludington Unit 1-6 DCS Control Relay Replacement	\$ 1,347,516	\$ 727,000

Below is a discussion of the remaining million-dollar projects whose actual 2023 capital expenditures were less than projected:

- Zeeland Heat Recovery Steam Generator (“HRSG”) Casing Replacement (\$2,803,333). This project is scheduled to be completed in 2024. The Company

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spent a total of \$699,676 in 2023 and \$2,097,620 is scheduled for the projected bridge period ending February 28, 2025;

- Zeeland Generator Step Up Transformer Replacement (Spare) (\$2,883,33). During 2023, the Company spent a total of \$758,314 on this project, \$589,607 is planned for the bridge period ending February 28, 2025, and \$6.449 million is planned for the test year ending February 28, 2026;
- Five Channels Dead Bay and Log Chute Remediation (\$1,981,666). This project was completed in 2023; however, the project was entirely a removal project. As such, a total of \$2,134,312 was recorded to cost of removal and a negative \$331,235 was recorded to capital;
- Ludington Replace Barrier Net Panels (\$1,088,614). The Company spent a net total of \$705,769 in 2023 as a result of an offset of \$747,499 from the Ludington co-owner; and
- Karn Units 3 and 4 Separation (\$1,789,545). The separation work was performed in 2023; however, a large portion of the expense was recorded to cost of removal. The Company pursued a separate project (Karn Units 3 and 4 boiler plant heating) as an alternative to upgrading the auxiliary boilers as part of the utility separation. I will discuss that project later in this direct testimony.

Q. Please discuss the 2023 capital projects that were not included in Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, that are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7.

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

- Covert Information Technology (“IT”) Room (\$2,059,520). The scope of this project was to provide the plant connectivity to the Consumers Energy’s SCADA and corporate networks while keeping the plant fully operational during the transition from the legacy network to Consumers Energy networks. The North American Electric Reliability Corporation (“NERC”) Critical Infrastructure Protection (“CIP”) regulation requires that the SCADA and corporate networks be separate from each other and, due to the legacy network needing to remain operational during the transition, IT required a new IT Room to be built to house the corporate network infrastructure;
- Covert Security and Network (\$2,208,169). The scope of this project was to ensure the plant is meeting the physical security requirements for CIP Low assets. Due to the plant having minimal CIP Low physical security assets in place, Consumers Energy’s corporate security team was required to install new cameras and card readers throughout the site where all CIP Low assets reside;

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- 1 • Covert Spare Generator Stepup (“GSU”) Transformer (\$1,722,987). The scope
2 of this project is the procurement of a spare transformer for the Covert
3 Generating Station. The 2023 capital expenditure reflects a milestone payment
4 to the best identified bidder and internal loadings. This project will be discussed
5 in more detail later in this direct testimony;
- 6 • Karn Units 3 and 4 Boiler Plant Heating (\$4,836,052). The Karn Units 3 and
7 4 Plant Heating Boilers Project was a strategic initiative aimed at upgrading the
8 plant heating system at Karn Power Station. The project involved the
9 procurement and installation of two smaller, more efficient boilers for
10 continuous plant heating. Prior to implementing this project, the existing
11 auxiliary boilers were utilized, and the auxiliary boilers were both inefficient
12 and unreliable for continuous plant heating. Originally, the auxiliary boilers
13 were to be used for plant heating and were to be addressed as part of the Karn
14 Units 3 and 4 separation as previously discussed in this direct testimony;
- 15 • Karn Unit 3 Exciter Rewind (\$1,038,719). The scope of this project was to
16 remove the Karn Unit 3 Exciter Rotor and send it out to be rewound. This work
17 was required as a result of the main lead in the exciter rotor failing open. Once
18 the exciter was disassembled at the vendor facility, the broken lead and the
19 resulting inability to excite was identified. To repair the broken main lead, a
20 full rewind was needed because the main lead was buried under the windings;
- 21 • Jackson Multimedia Filtration Pilot Skid (\$2,441,755). The scope of this
22 project was to perform testing and calibration as well as provide system
23 improvements to the treatment systems for the well water. The specific scope
24 of the project includes the installation of larger bleach pumps in order to pump
25 a higher flowrate of bleach to counteract the bleach degradation, replacement
26 of caustic pumps on caustic injection system due to issues with pump
27 performance, replacement of variable frequency drive and breaker damaged by
28 caustic injection system, replacement of control valve on well water forwarding
29 pump to increase the flowrate up to the required 1,150 gpm, adjustment of the
30 logic in the reverse osmosis pretreatment system to remove ability for all
31 (4) beds to backwash at the same time, run various scenarios to optimize the
32 throughput of the greensand filters, the caustic in the pretreatment, and the
33 bleach in the pretreatment, and other system improvement activities;
- 34 • Zeeland Unit 5 GSU Transformer Rewind (\$13,884,854). The scope of this
35 project was to remove the failed Zeeland Unit 5 GSU transformer, movement
36 and installation of the spare GSU transformer, and sending out the failed
37 Zeeland Unit 5 GSU transformer for overhaul which included milestone
38 payments for the overhaul. In addition, the scope reflected the monthly lease
39 of a spare transformer to provided continued operation of the unit for customers.
40 Zeeland Unit 5 was taken out of service on December 17, 2022 and was returned
41 to service on January 23, 2023 upon installation of the leased transformer which
42 was moved from Zeeland Unit 1; and

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- Croton 1 and 2 Wicket Gate (\$4,329,769). This projected was originally expected to be completed in 2022 however during project implementation a significant amount of additional work was identified during project execution.

PROJECTED 14-MONTH BRIDGE PERIOD CAPITAL EXPENDITURES

Q. How does the projected 14-month bridge period capital expenditure of \$464 million compare to the amount of capital approved by the MPSC in Case No. U-21389 for 2024?

A. The 14-month bridge period projected capital expenditure amount of \$463.548 million is \$5 million less than the projected test year amount of \$468.684 million requested in the Company's last electric rate case (Case No. U-21389). The difference between the 14-month bridge amount requested in Case No. U-21389 and the amount requested in this proceeding includes changes in the projects for which recovery is being requested. For example, the inclusion of projected capital expenditures for BESSs is offset by the reduction in projected costs for IRP solar projects. Each of these project areas are discussed in more detail in witness Clark's direct testimony. A compilation of the 14-month bridge period projects which have projected capital expenditure amounts greater than \$1 million is presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8.

Q. How does the compilation of 14-month bridge period capital projects on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, compare with the test year capital projects reflected on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 10?

A. A comparison of the 14-month bridge period capital projects on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, with the test year projects reflected on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 10, reveals that there are 26 projects on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, which were not reflected on Case No. U-21389, Exhibit

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A-12 (RTB-3), Schedule B-5.1, page 8. In addition, there were 17 projects for the 12-month period ending February 28, 2025 that were reflected on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 10, that are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8.

Q. Please discuss the test year capital projects that were included on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 10, that are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8.

A. The following projects are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, due to the fact that the projected bridge period capital expenditure amounts are now less than \$1 million or the project is not being pursued in the bridge period. The disposition of these capital projects is presented in the table below:

Site	Project	Disposition
Alcona	Risk Informed Decision Making Resolution	Disallowed in U-21389 Final Order
Cooke	Head Gate Replacement Project	Reflected in Test Year Investment
Covert	Non Long Term Service Agreement Capital - Extras	Disallowed in U-21389 Final Order
Five Channels	Trash Rack Ergonomics Project	Reflected in Test Year Investment
Foote	Unit 2 Wicket Gates Replacement Project	Project Deferred by Company in U-21389
Foote	ADA Ramp Investigation and replacement	Project Deferred by Company in U-21389
Hardy	Electrical Safety Project	Project Deferred by Company in U-21389
Hardy	Hardy Splash Wall Replacement	Disallowed in U-21389 and moved to test year
Hodenpyl	Downstream Wall	Reflected in Test Year Investment
Jackson	LM 1 - 6 SAC Extended Life Combustor	Project Deferred by Company in U-21389
Ludington	Administrative Building Addition	Project Deferred by Company in U-21389
Ludington	Replace Barrier Net Panels	Staff reduced project spend to \$0.476 million
Ludington	Intake Gate and Gate House Mechanical Replacement	Staff reduced project spend to \$0.700 million
Solar	Solar - 2019 Bid Event (Mustang Mile 150 MW)	Disallowed in U-21389 Final Order
Solar	Solar - 2020 Bid Event (Washtenaw Solar) (150 MW)	Disallowed in U-21389 Final Order
Webber	Unit 1 Generator Rewind	Project Deferred by Company in U-21389
Zeeland	Purchase of Site Spare GSU	Reflected in Test Year Investment

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Q. Please identify the 14-month bridge period capital projects that were not included on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 10, that are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9.

A. The bridge period capital projects that were not included on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 10, are presented in the table below:

Line No.	Project Description
1	Covert Purchase of site spare GSU
2	Covert Cooling Tower Gearboxes
3	Covert SCR/CO Catalyst Replacement - Unit 2
4	Covert SCR/CO Catalyst Replacement - Unit 3
5	Covert 1-3 Emerson DCS Evergreen
6	Jackson GE LTSA Historical Extra Work Expected
7	Zeeland 2C GSU Rewind
8	Zeeland Phase I Gas Turbine Advanced gas path replacement and axial fuel staging
9	Zeeland LTSA - Extras not included in contract (cranes, mobile equipment)
10	Zeeland Long Term Service Agreement - Running Capital Contract
11	Zeeland HRSG Casing Replacement
12	Karn 3 DCS Evergreen
13	Karn 3&4 Sync Wire Replacement
14	Karn 4 Replacement of Ductwork Insulation and Lagging
15	Karn 4 DCS Evergreen
16	LPS - LPEJ Chamber water stop replacement
17	Alcona Artesian Design Study
18	Foote Spillway Hoist Replacement
19	Hardy Auxiliary Spillway Replacement
20	Hodenpyl - Emergency Spillway Project
21	Hodenpyl Spillway Hoist Replacement
22	Tippy - Unit 1 Thrust Bearing Replacement
23	Solar - 2022 Bid Event (Spring Creek)
24	Armstrong BESS (IIJA Grant App)
25	Iosco BESS (IRP)
26	Weadock BESS (IRP)

The basis for projects 1 through 16 will be discussed in more detail later in this direct testimony, the basis for projects 17 through 22 will be discussed in the direct testimony of Company witness Monroe, and the basis for projects 23 through 26 will be discussed in the direct testimony of Company witness Clark.

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1 **Q. Is the projected capital expenditure amount of \$463.548 million for the 14-month**
2 **bridge period ending February 28, 2025, on Exhibit A-12 (RTB-3), Schedule B-5.2,**
3 **page 1, column (e), consistent with the Company's generation asset strategy?**

4 A. Yes. Based upon a review of the projected capital expenditure presentation on Exhibit
5 A-12 (RTB-3), Schedule B-5.2, pages 2 and 3, lines 1 through 99, column (h),
6 \$249.572 million of that capital will fund solar projects pursuant to the Company's IRP,
7 \$39.672 million will fund BESS projects, \$118.854 million of that total capital expenditure
8 amount will be used at the Company's natural gas generating facilities which includes
9 Covert, Jackson, Zeeland, and Karn Units 3 and 4. In addition, \$10.279 million will fund
10 various projects at the LPS facility, and \$42.376 million will fund various hydro safety,
11 reliability, and regulatory compliance projects. With the exception of the solar, BESS, and
12 the River Hydro projects, a detailed discussion of the various projects for each generating
13 unit or group of generating units will be provided later in this direct testimony. The River
14 Hydro projects will be discussed in the direct testimony of Company witness Monroe and
15 the solar projects will be discussed in the direct testimony of Company witness Clark.

16 **PROJECTED TEST YEAR CAPITAL EXPENDITURES**

17 **Q. Is the projected capital expenditure amount of \$600.484 million for the test year**
18 **ending February 28, 2026, on Exhibit A-12 (RTB-3), Schedule B-5.2, page 1,**
19 **column (f), consistent with the Company's generation asset strategy?**

20 A. Yes. Based upon a review of the projected capital expenditure presentation on Exhibit
21 A-12 (RTB-3), Schedule B-5.2, pages 2 and 3, lines 1 through 99, column (j),
22 \$275.959 million of that capital will fund solar projects pursuant to the Company's IRP,
23 \$78.921 million will fund BESS projects, \$134.664 million of that total capital expenditure

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1 amount will be used at the Company's natural gas generating facilities which includes
2 Covert, Jackson, Zeeland, and Karn Units 3 and 4. In addition, \$15.587 million will allow
3 the Company to complete various regulatory, reliability, and infrastructure projects
4 necessary to support the 50-year license extension at Ludington granted by FERC in 2019
5 and \$92.258 million will fund various hydro safety, reliability, and regulatory compliance
6 projects. Except for the solar projects and the River Hydro projects, a detailed discussion
7 of the various projects for each generating unit or group of generating units will be provided
8 later in this direct testimony. The River Hydro projects will be discussed in the direct
9 testimony of Company witness Monroe and the solar projects will be discussed in the direct
10 testimony of Company witness Clark.

11 **Campbell Units 1, 2, and 3**

12 **Q. Please explain the Company's projected capital investment for the 14-month**
13 **projected bridge period ending February 28, 2025 and projected test year ending**
14 **February 28, 2026 for Campbell Units 1, 2, and 3.**

15 **A.** The Company does not plan to invest any capital in the Campbell units during the bridge
16 period or test year, as reflected on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, lines 1
17 and 8. As presented on Exhibit A-43 (RTB-4), lines 1 and 2, and as discussed later in this
18 direct testimony, the Company has projected modest amounts of major maintenance to
19 ensure that these units are able to operate through their retirement date of May 31, 2025.

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Covert Plant

Q. Please explain the Company's projected capital investment for the 14-month projected bridge period ending February 28, 2025 and projected test year ending February 28, 2026 for Covert.

A. The Company plans to invest a total of \$34.087 million in the 14-month bridge period and \$61.483 million in the test year at the Covert Plant. These capital investments will be facilitated by nine-day outages at Covert Units 1 through 3 in the spring and fall of 2025 as well as longer unit outages for major inspections. Covert Unit 1 has a 58-day outage scheduled to begin on February 1, 2026, Covert Unit 3 has a 59-day outage scheduled to begin on November 1, 2025, and Covert Unit 2 has a 58-day outage scheduled to begin on February 1, 2025.

Q. Please explain the Company's projected capital investment for the 14-month bridge period ending February 28, 2025 for the Covert Plant.

A. The Company plans to invest a total of \$34.087 million in the bridge period on the Covert Plant, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 43, column (h).

Q. What is the basis for the projected \$34.087 million capital investment in the 14-month projected bridge period?

A. The projected \$34.087 million capital investment in the projected bridge period will fund numerous projects at the Covert Plant. Six of these projects are greater than \$1 million, and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 1 through 6.

The basis for these six projects is described below:

- Purchase of site spare GSU (1,000,000). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;

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- Cooling Tower Gearboxes (\$1,161,732). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Selective Catalytic Reduction (“SCR”)/Carbon Monoxide (“CO”) Catalyst Replacement - Unit 2 (\$1,041,667). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- SCR/CO Catalyst Replacement - Unit 3 (\$1,041,667). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Covert Units 1 through 3 Emerson Distributed Control System (“DCS”) Evergreen (\$1,041,250). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert; and
- Covert Plant Long-Term Service Agreement (“LTSA”) (\$20,400,000). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert.

The following projects are less than \$1 million, but are important to reliability:

- Covert Plant (Units 1, 2, and 3) LTSA extra work (\$1,748,333 total). The LTSA extra work is defined as the work that is not covered under normal planned maintenance in the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items not covered under the LTSA that need to be addressed are labor and material to replace the following: blading, ammonia delivery system, SCR catalyst, turbine rotors, cooling towers, and turbine cooling air cooler;
- Excitation Replacement (\$340,000). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Office Space Consumers Energy Warehouse with Loading Dock (\$493,333). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Plant Replace Sulfuric Sodium Hypo and Building (\$410,000). The Sodium Hypochlorite system is original, in poor condition, and has experienced multiple failures, creating a safety hazard for the operators. Additionally, this equipment is housed in the same building as the sulfuric acid dosing system with only a fiberglass dividing wall. If both systems were to experience a leak at the same time, that situation could generate poisonous chlorine gas;

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- Gas Turbine Generator (“GTG”)/ Steam Turbine Generator (“STG”) Replace Covert Units 1 through 3 Rollup Doors (\$535,000). The Covert Plant faces a significant operational challenge due to the absence of overhead roll-up doors on the south side of the power block building. This infrastructure limitation necessitates the removal of building panels to facilitate the ingress and egress of large equipment, such as STGs and GTGs, during major outages. This project will install insulated rollup doors with electrical power. By installing insulated roll-up doors, the Covert Plant can eliminate the time-consuming and costly process of panel removal and reinstallation. This upgrade streamlines access for large equipment, reducing downtime and associated labor costs. In addition, the insulated design and weather stripping of the Model 625 doors provide significant protection against cold air infiltration, safeguarding critical equipment during outage periods in cold weather;
- Netmation (Operating System & 4S) - Unit 2 (\$391,667). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Netmation (Operating System & 4S) - Unit 3 (\$300,833). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Gas Compressor Controls Replacement (Programmable Logic Controller (“PLC”) replacement) (\$424,4000). Gas Compressors (two in total) operate using a local control network consisting of a human machine interface (“HMI”) (Panel View 1000) and Allen Bradley PLC five controllers. This equipment has reached end of life and replacements are no longer available. The Covert site currently has one failed board in service. This project would utilize existing panels and replace the equipment with an Allen Bradley ControlLogix solution and PanelView Plus 7;
- Covert Units 1, 2, and 3 – MV90 Revenue Meters for MISO (\$570,000). The scope of this project is the replacement of the existing meters utilized to record power flows for purposes of reporting to MISO for market settlement;
- Linear Variable Differential Transformers (“LVDT”) Positioning Sensor – Unit 1 Fuel Control Valves (\$737.930). The scope of this project is to replace the Yokogawa 5516 mechanical type position sensors with LVDTs. The replacement is to include the following devices, Main “A” pressure control fuel valve sensor, Main “B” pressure control fuel valve sensor, Main flow control fuel valve sensor, Pilot pressure control fuel valve sensor, and the pilot flow control fuel valve sensor and compressor bypass actuator. The benefits of this project include reduced maintenance, improved accuracy, and higher long-term reliability due to the removal of the mechanical linkages and converting to a non-contact mechanism;

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The Covert Mitsubishi Power Gas turbines are equipped with Yokogawa 5516 mechanical linkage type position sensors. The Yokogawa position sensors are used to detect the position of the fuel control valves, bypass valve actuators, and the Inlet Guide Vanes. These valves and their position are critical as they control turbine output which allows more load on the generator and meets load demand. The Yokogawa 5516 position sensors are obsolete, and Yokogawa has announced that the 5516 position sensors are no longer manufactured as of March 31, 2015, no longer supported, and parts are no longer available. Mitsubishi Power recommends eliminating the Yokogawa mechanical linkage position sensors;

- Covert Base Outage Capital (\$443,333). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages; and
- Twenty additional projects at Covert totaling \$1.650 million which support safety, security, and reliability, with each project representing \$201,667 or less in capital expenditures. These projects include load commutated inverter Replacements, Unit 2 Power Distribution Center ("PDC") Battery Replacement, Electronic Overspeed protection, site small capital, LVDT Positioning Sensor – Unit 2, and SCR/CO Replacement - Unit 1.

Q. What is the basis for the projected \$61.483 million capital investment in the projected test period?

A. The projected \$61.483 million capital investment in the projected test period will fund numerous projects at the Covert Plant. Ten of these projects are greater than \$1 million, and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 1 through 10. The basis for these projects is described below:

- Purchase of site spare GSU transformer (\$4,500,000). Covert Generating Station consists of three gas turbine powered plants and three steam turbine powered plants placed in a one-on-one combined cycle configuration. The units transmit their power to the grid via GSU transformers. Each gas turbine powered unit feeds the secondary winding of a three-winding transformer, while the associated steam powered unit feeds the tertiary winding of the transformer. The GSU is rated for 500 MVA with forced oil and forced air. If a GSU were to fail, then the associated turbines would not be able to transmit power and would not be able to generate market value for Consumers Energy and its customers. The lead time for a GSU is currently three-to-four years and spare units at other facilities typically do not exist, especially for this more unique design application;

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This project provides a spare GSU for Covert which: 1) Greatly reduces unit downtime in the event of GSU issues or failure requiring removal and lowers the total financial losses in such events; 2) Allows for easier engineering design and planning to install a spare or replacement GSU ahead of any emergent installation needs; 3) Mitigates potential issues from installing GSUs not specifically designed for this location, system or application and/or doing it multiple times in a short time period; 4) Would allow for Consumers Energy to enter lease agreements with other utilities who may be in need of a spare to recover some costs of the spare purchase over time; and 5) The oil analysis of Covert transformers revealed the presence of chemicals for corrosive sulfur. Mitigating actions are being taken, however, this failure mode puts these transformers at increased risk of failure;

- Office Space Consumers Energy Warehouse with Loading Dock (\$1,816,667). The scope of this project is to build out the existing warehouse and add a loading dock. The existing warehouse does not meet the needs for the upcoming major outages, or plant maintenance in the future. The addition of a loading dock will provide for safer and efficient loading/unloading of trucks. In addition, the current onsite office space is inadequate, and it will be expanded;

Cooling Tower Gearboxes (\$1,039,192). The Covert Generating Station Cooling Tower Fan Gearbox Replacement Project addresses critical operational issues stemming from the end-of-life status of gearboxes after over 20 years of service. These gearboxes are essential for cooling tower fan operations, affecting the station's overall efficiency and reliability. The scope of this project is to replace the existing cooling tower gearboxes with gearboxes from the same manufacturer, an alternative that avoids additional modifications. Covert operates three 6-cell cooling towers corresponding to each of its units. These cooling towers play a crucial role in the station's operational efficiency by facilitating the removal of residual heat from circulating water. This process is essential after the water has been utilized for condensing steam produced by the steam turbines. Operational challenges with the gearboxes include increased gearbox failures, inadequate heat removal due to malfunctioning cooling tower fans, and obsolete motor starters;

- Netmation (Operating System & 4S) - Unit 2 (\$1,458,333). The Covert gas generating station, operational since 2004, faces critical challenges with its outdated control systems. These challenges impact both operational efficiency and cybersecurity, necessitating an urgent upgrade to modern standards. The scope of this project is an extensive upgrade of the Covert Mitsubishi Turbine Control System to the latest version of Netmation, which includes the replacement of hardware, I/O modules, servers, workstations, network switches, and software to the latest architecture;
- Covert Units 1 through 3 Emerson DCS Evergreen (\$2,448,750). The scope of this project is to upgrade the DCS to the latest version in order to enhance security, gain compliance with enterprise standards, and achieve technological

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1 advancement. Covert, which has been operational since 2004, faces significant
2 challenges with its Emerson Ovation DCS. The system's obsolescence,
3 cybersecurity risks, and operational inefficiencies necessitate an urgent upgrade
4 to the latest version to enhance reliability, security, and compliance with
5 regulatory standards. The DCS that controls all equipment in the plant (along
6 with the Mitsubishi gas turbine controls), is Emerson Ovation DCS. It was
7 upgraded about 10 years ago to the current version. Emerson Ovation version
8 3.5.1 is no longer supported by Emerson or Microsoft. The Emerson Ovation
9 version 3.5 system entered a retired status in June 2019. The Windows
10 operating systems that are used by this version of Ovation are Windows 7 and
11 Windows Server 2008R2. Microsoft ended extended support of Server 2008R2
12 in January 2020.

13 The generation plant control systems are an important part of the nation's
14 Critical Infrastructure and fall under NERC CIP requirements. To keep the
15 Company's control systems secure, Consumers Energy must patch the
16 operating systems and applications that run its plants. The Company is no
17 longer able to patch and maintain these operating systems, such as Microsoft
18 Windows, or applications, such as Ovation, when they are no longer supported
19 by the manufacturers. The systems at Covert do not meet corporate
20 cybersecurity standards and are operating with security exception to the
21 Company's standards.

22 The cybersecurity tools (Power Water Cybersecurity Suite ("PWCS"))
23 being utilized for the Covert control network device patching and antivirus
24 protection require replacement to allow continued patching and protection with
25 a new DCS version. The current version of PWCS is nearing end of support
26 and requires updating to allow support of the latest Ovation versions.

27 The Balance of Plant ("BOP") control is achieved with the Ovation DCS.
28 Its architecture is comprised of controller and operator "drops" (processors and
29 PCs) that provide the control of the equipment with input/output ("I/O")
30 modules. Some of these I/O modules are in the same electrical cabinets that
31 contain the "controller drops" (processors). Other I/O is in "remote" electrical
32 cabinets, away from the "controller drops." The existing plant control is
33 comprised of many remote I/O cabinets throughout the site. The
34 communication modules to these cabinets have experienced failures in the past
35 that can trip the generating units offline. Power supplies in the Ovation cabinets
36 have reached the end of their recommend life and need to be replaced. The
37 architecture and components need to be upgraded and replaced with the latest
38 Ovation design.

39 The main controller drop that operates a large part of the BOP equipment
40 has had equipment and data link controls added to it over the years. It controls
41 equipment for all three (3) generating units. The controller drop needs to have
42 part of its I/O and logic split off to new controller drops. The partitioning of I/O

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1 to other drops should allow the upgrade and maintenance procedures to occur
2 and reduce the need of a site outage to perform these activities. Risk to unit
3 trips should be reduced to individual generating units instead of all units on the
4 site;

- 5 • Netmation (Operating System and 4S) – Unit 3 (\$1,504,167). The Covert gas
6 generating station, operational since 2004, faces critical challenges with its
7 outdated control systems. These challenges impact both operational efficiency
8 and cybersecurity, necessitating an upgrade to modern standards. The scope of
9 this project is an extensive upgrade of the Covert Mitsubishi Turbine Control
10 System to the latest version of Netmation, which includes the replacement of
11 hardware, I/O modules, servers, workstations, network switches, and software
12 to the latest architecture;

- 13 • Covert Plant LTSA (\$14,700,000). This is the capital portion for Mitsubishi
14 negotiated services that cover the planned normal maintenance of each
15 generating unit. The projected capital expenditures are based upon variable fees
16 paid to Mitsubishi for maintenance services which are based on an Effective
17 Fired Hour basis pursuant to the LTSA. Unlike the GE LTSAs for the Jackson
18 and Zeeland plants, there are no milestone payments associated with the fee
19 structure for the Mitsubishi LTSA. Based on the OEM's operating and
20 historical experience, if the Company executes the normal planned maintenance
21 and inspections according to the recommended schedules, the Company will
22 mitigate unexpected pre-mature failures of the equipment. This will help
23 maximize availability and, as a result, optimize customer value for the site.
24 Normal maintenance will ensure the Company continues reliable operation of
25 the units. During the bridge period and test year, the Company will be
26 conducting major inspections on all three generating units, and a portion of the
27 work to be performed is not covered in the LTSA, rather it is covered in the
28 LTSA extra work as described below;

- 29 • Covert Unit 1 LTSA extra work (\$1,437,717). The LTSA extra work is defined
30 as the work that is not covered under normal planned maintenance in the LTSA.
31 Based on historical outage experience there are typical discovery items found
32 on this style of gas turbines that are not part of the LTSA planned maintenance
33 scope. Some of the typical items not covered under the LTSA that need to be
34 addressed are labor and material to replace the following: blading, ammonia
35 delivery system, SCR catalyst, turbine rotors, cooling towers, and turbine
36 cooling air cooler. The major inspection for Covert Unit 1 begins on
37 February 1, 2026, just prior to the end of the test year, and ends on March 31,
38 2026. As such, a large portion of the LTSA extra work will not be requested in
39 this proceeding;

- 40 • Covert Unit 2 LTSA extra work (\$12,609,633). The LTSA extra work is
41 defined as the work that is not covered under normal planned maintenance in
42 the LTSA. Based on historical outage experience there are typical discovery
43 items found on this style of gas turbines that are not part of the LTSA planned

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1 maintenance scope. Some of the typical items not covered under the LTSA that
2 need to be addressed are labor and material to replace the following: blading,
3 ammonia delivery system, SCR catalyst, turbine rotors, cooling towers, and
4 turbine cooling air cooler. The major inspection on Covert Unit 2 begins on
5 February 1, 2025, and major work includes generator inspection, replacement
6 of the generator hydrogen seals, generator rewedge, diaphragm repairs, steam
7 turbine and generator bearing repairs, and HP stop and control valve
8 disassembly, inspection, cleaning, and repair. The Company's LTSA with
9 Mitsubishi Electric Power Products, Inc. ("MEPPI") does not cover this scope
10 of work; and

- 11 • Covert Unit 3 LTSA extra work (\$10,609,633). The LTSA extra work is
12 defined as the work that is not covered under normal planned maintenance in
13 the LTSA. Based on historical outage experience there are typical discovery
14 items found on this style of gas turbines that are not part of the LTSA planned
15 maintenance scope. Some of the typical items not covered under the LTSA that
16 need to be addressed are labor and material to replace the following: blading,
17 ammonia delivery system, SCR catalyst, turbine rotors, cooling towers, and
18 turbine cooling air cooler. The major inspection on Covert Unit 3 begins on
19 November 1, 2025, and major work includes generator inspection, replacement
20 of the generator hydrogen seals, generator rewedge, diaphragm repairs, steam
21 turbine and generator bearing repairs, and HP stop and control valve
22 disassembly, inspection, cleaning, and repair. The Company's LTSA with
23 MEPPI does not cover this scope of work.

24 The following projects are less than \$1 million, but are important to reliability:

- 25 • Excitation Replacement (\$761,667). The scope of this project is the
26 replacement of the steam turbine exciters. The existing excitation equipment is
27 obsolete, and the gas turbine exciters have already been replaced. A failure of
28 the steam turbine exciter could lead to both generators on the unit being out of
29 service until replacements can be found with a typical lead time of
30 18-24 months;
- 31 • Electronic Overspeed protection (\$678,333). The scope of this project is the
32 installation of an electronic overspeed trip upgrade. The plant has experienced
33 issues with their overspeed trip device in the past. The backup electronic
34 overspeed trip is reliable but is not redundant so that a single component failure
35 would not disable the trip. The primary protection on the steam turbines are the
36 mechanical overspeed trip mechanisms. The mechanical overspeed trip
37 mechanism must be tested (offline) periodically to ensure that its setpoint has
38 not changed and that it can trip the unit;
- 39 • Flame Detectors for Gas Turbine Wheel temperature Digital replacement
40 (\$397,083). The scope of this project is to replace the existing mechanical
41 flame detection system with digital flame detection system. The existing

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1 system is obsolete and has reliability issues that a new digital system would
2 resolve;

- 3 • SCR/CO Catalyst Replacement - Unit 2 (\$708,333). The scope of this project
4 is the replacement of the catalyst for the SCR. This replacement is based upon
5 the expected degradation of the exiting catalyst and effective operation of the
6 SCR is required to meet environmental regulations;

- 7 • SCR/CO Catalyst Replacement – Unit 3 (\$708,333). The scope of this project
8 is the replacement of the catalyst for the SCR. This replacement is based upon
9 the expected degradation of the exiting catalyst and effective operation of the
10 SCR is required to meet environmental regulations;

- 11 • Netmation (Operating System and 4S) – Unit 1 (\$375,000). The Covert gas
12 generating station, operational since 2004, faces critical challenges with its
13 outdated control systems. These challenges impact both operational efficiency
14 and cybersecurity, necessitating an urgent upgrade to modern standards. The
15 scope of this project is an extensive upgrade of the Covert Mitsubishi Turbine
16 Control System to the latest version of Netmation, which includes the
17 replacement of hardware, I/O modules, servers, workstations, network
18 switches, and software to the latest architecture;

- 19 • Balance Of Plant Valves – Unit 2 (\$590,000). The scope of this project is the
20 repair and/or replacement of balance of plant valves. The plant has a long list
21 of valves that require attention. The condenser bypass valves will be addressed
22 in the major outage scheduled for March 1, 2025 through March 31, 2025 and
23 they represent a large expense;

- 24 • Balance Of Plant Valves – Unit 3 -(\$590,000). The scope of this projects is the
25 repair and/or replacement of balance of plant valves. The plant has a long list
26 of valves that require extensive maintenance. The condenser bypass valves will
27 be addressed in the major outage scheduled for November 1, 2025 through
28 December 30, 2025 and they represent a large expense;

- 29 • Positioning Sensor – Unit 3 (\$687,500). The scope of this projects is to replace
30 the Yokogawa 5516 mechanical type position sensors with LVDTs. The
31 replacement to include the following devices, Main “A” pressure control fuel
32 valve sensor, Main “B” pressure control fuel valve sensor, Main flow control
33 fuel valve sensor, Pilot pressure control fuel valve sensor, and the pilot flow
34 control fuel valve sensor and compressor bypass actuator. The benefits of this
35 project include reduced maintenance, improved accuracy, and higher long-term
36 reliability due to the removal of the mechanical linkages and converting to a
37 non-contact mechanism. The Covert Mitsubishi Power Gas turbines are
38 equipped with Yokogawa 5516 mechanical linkage type position sensors. The
39 Yokogawa position sensors are used to detect the position of the fuel control
40 valves, bypass valve actuators, and the Inlet Guide Vanes. These Valves and
41 their position are critical as they control turbine output which allows more load

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on the generator and meets load demand. The Yokogawa 5516 position sensors are obsolete, and Yokogawa has announced that the 5516 position sensors are no longer manufactured as of March 31, 2015, are no longer supported and parts are no longer available. Mitsubishi Power recommends eliminating the Yokogawa mechanical linkage position sensors;

- SCR/CO Catalyst Replacement – Unit 1 (891,667). The scope of this project is the replacement of the catalyst for the SCR. This replacement is based upon the expected degradation of the exiting catalyst and effective operation of the SCR is required to meet environmental regulations;
- Covert Base Outage Capital (\$383,333). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages;
- LVDT Positioning Sensor - Unit 2 (645,833). The scope of this projects is to replace the Yokogawa 5516 mechanical type position sensors with LVDTs. The replacement to include the following devices, Main "A" pressure control fuel valve sensor, Main "B" pressure control fuel valve sensor, Main flow control fuel valve sensor, Pilot pressure control fuel valve sensor, and the pilot flow control fuel valve sensor and compressor bypass actuator. The benefits of this project include reduced maintenance, improved accuracy, and higher long-term reliability due to the removal of the mechanical linkages and converting to a non-contact mechanism.

The Covert Mitsubishi Power Gas turbines are equipped with Yokogawa 5516 mechanical linkage type position sensors. The Yokogawa position sensors are used to detect the position of the fuel control valves, bypass valve actuators, and the Inlet Guide Vanes. These Valves and their position are critical as they control turbine output which allows more load on the generator and meets load demand. The Yokogawa 5516 position sensors are obsolete, and Yokogawa has announced that the 5516 position sensors are no longer manufactured as of March 31, 2015, no longer supported, and parts are no longer available. Mitsubishi Power recommends eliminating the Yokogawa mechanical linkage position sensors; and

- Eighteen additional projects at Covert totaling \$1.941 million which support safety, security, and reliability, with each project representing \$408,333 or less in capital expenditures. These projects include BOP Valves - Unit 1 MI, Unit 1 and Unit 3 PDC Battery Replacement (NERC), Load Commutated Inverter replacements, Gas Turbine - Units 1 through 3 Evaporator Media, and site small capital.

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Karn Units 1 and 2

Q. Please explain the Company's projected capital investment for the 14-month projected bridge period ending February 28, 2025 and the projected test year ending February 28, 2026 for Karn Units 1 and 2.

A. The Company does not plan to make any capital investments on Karn Units 1 and 2 in the 14-month projected bridge period ending February 28, 2025 or the projected test period ending February 28, 2026, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 15, columns (h) and (j), respectively, due to their retirement on May 31, 2023.

Karn Units 3 and 4

Q. Please explain the Company's projected capital investment for the 14-month projected bridge period ending February 28, 2025 and the projected test year ending February 28, 2026, for Karn Units 3 and 4.

A. The Company plans to invest \$17.119 million in the projected bridge period and \$7.287 million in the projected test period, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 22, columns (h) and (j), respectively.

Q. What is the basis for the projected \$17.119 million capital investment in the 14-month projected bridge period?

A. The projected \$17.119 million capital investment will fund numerous safety, regulatory compliance, reliability, and infrastructure projects at Karn Units 3 and 4. There are six projects which are greater than \$1 million, and these projects are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 14 through 19.

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1 **Q. Did the Order in the Company's 2023 Electric Rate Case (Case No. U-21389) establish**
2 **any specific requirements for any of the Karn site projects?**

3 A. Yes. Paragraph C on page 309 of the March 1, 2024 Order in Case No. U-21389 required
4 the following:

5 "Consumers Energy Company shall file in its next general
6 electric rate case an alternatives analysis addressing the
7 replacement of the Karn Unit 3 Cooling Tower internal
8 structure, including information on the most cost-efficient
9 solution and alternatives to full replacement as described in
10 this order."

11 **Q. What is the scope of the project?**

12 A. The scope of this project is the replacement of the structural timbers, remaining stacks, and
13 fan blades on Karn Unit 3's cooling tower. The wooden structure is original equipment
14 and has decayed since its installation. The cooling tower provides cooling water for the
15 condenser. The wooden cooling tower structure supports 18 large fans that pull air through
16 the water to drive the evaporation process to cool the water. The wooden structure also
17 supports large water pipes that carry the cooling water to the fill. The water flow to the
18 tower is approximately 240,000 gallons per minute. The entirety of this weight is
19 supported by the wooden structure as it is conveyed to the tower and cascades over the fill.
20 Implementation of this project will provide for reliable operation of Karn Unit 3 through
21 its retirement in 2031. The projected cost for this project in the 14-month bridge period is
22 \$6.0 million.

23 **Q. Has the Company performed an alternative analysis?**

24 A. Yes. The Company has created a concept approval to document its evaluation of the project
25 and the potential alternative. The concept approval is presented as Exhibit A-45 (RTB-6).

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As established in Exhibit A-45 (RTB-6), the cooling tower internal structure was in poor condition and viable options were limited.

Q. Please discuss the basis for the remaining projects for Karn Units 3 and 4.

A. The basis for the remaining projects greater than \$1 million are described below:

- Karn Units 3 and 4 Sync Wire Replacement (\$1,260,000). The scope of this project is the replacement of the existing copper communication cables between the plant and Hampton Substation. The replacement will consist of fiber optic communication cable from Hampton Substation to the plant and the replacement of Karn Units 3 and 4 generating unit line protection relays, pilot wire differential line protection relaying, telemetry, and control communication at Hampton Substation. Telemetry and control include but are not limited to breaker position indication, breaker control, transfer trip, bus voltage, and current indication. The Karn Units 3 and 4 auto-synchronizing relay is obsolete. This project will provide a modern reliable communication medium between Karn Units 3 and 4 and Hampton Substation, where the generator synchronization breakers reside. This medium will allow for a reliable means of communication between Karn Units 3 and 4 and the Hampton Substation, thereby reducing the risk of possible failure of the units to synchronize correctly or to trip the units offline for a fault event; potentially causing damage to the generator and turbine, resulting in decreased plant reliability and increased expense;
- Karn Units 3 and 4 Plant Heating Boiler (\$1,760,000). The scope of this project is the continuation of the installation of boilers for heating Karn Units 3 and 4. The remaining work to be accomplished in the bridge period includes the following:
 1. Installation of Gas Regulators which required modifications to the already installed gas piping;
 2. Installation new Steam Check Valve;
 3. Conduct Preliminary Air Check prior to hydro to identify any leaks before the State Boiler Inspector was on site;
 4. Install Sump Drains at multiple locations;
 5. Replace Day Tank Steam System Valves;
 6. Install additional Steam Traps;
 7. Install stack extension and stack drains;
 8. Install additional heat trace and insulation; and
 9. Install enclosure around Deaerator.

The Plant Heating Boilers Project is a strategic initiative aimed at upgrading the plant heating system at Karn Power Station. The project involves the procurement and installation of two smaller, more efficient boilers for continuous plant heating. Prior to implementing this project, the existing

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auxiliary boilers were utilized, and the auxiliary boilers were both inefficient and unreliable for continuous plant heating. Originally, the auxiliary boilers were to be used for plant heating and were to be addressed as part of the Karn Units 3 and 4 separation as previously discussed in this direct testimony;

- Karn Unit 3 Combustion Air Heaters (\$2,200,000). The combustion air heaters A and B had excessive tube leaks that were pressure tested and plugged during the fall 2022 outage. The B section has the worst damage with an estimated 50% of the tubes out of service. The scope of work for this project includes the replacement of two sections of the combustion air heater. The heater condition is causing a 68 MW derate on the unit;
- Karn Unit 4 DCS and Simulator Upgrade Evergreen (\$1,363,000). This project replaces the Karn Unit 4 Ovation DCS with the latest version available at the time of the project. The system is currently running on a VMware virtualized system. The system was installed in 2015 and software upgraded in 2019. This Evergreen will replace the existing Ovation Software, Operating Systems, and miscellaneous upgrades, the controller drops, and rack-mounted servers will be replaced for this upgrade. The DCS must be upgraded at a four-to-five-year upgrade cycle to maintain reliable control and provide recent operating systems and applications that are patchable. Vendor life cycle for DCS versions is generally a five-year cycle. After five years they enter a retired state and are no longer patched. Microsoft Operating Systems are on a limited life basis, and they reach the end of “extended support” and no longer get security patches. Corporate policies require all systems to be patched regularly along with Anti-Virus updates; and
- Karn Unit 3 DCS and Simulator Evergreen (\$1,507,000). This project replaces the Karn Unit 3 Ovation DCS with the latest version available at the time of the project. The system is currently running on a VMware virtualized system which was installed in 2019. This Evergreen will only replace the existing Ovation Software, Operating Systems, and miscellaneous upgrades. The controller drops and rack-mounted servers will not be replaced for this upgrade. The DCS must be upgraded at a four-to-five-year upgrade cycle to maintain reliable control and provide recent operating systems and applications that are patchable. Vendor life cycle for DCS versions is generally a five-year cycle. After five years they enter a retired state and are no longer patched. Microsoft Operating Systems are on a limited life basis, and they reach the end of “extended support” and no longer get security patches. Corporate policies require all systems to be patched regularly along with Anti-Virus updates.

The following projects are less than \$1 million, but are important to reliability:

- Karn Units 3 and 4 Ductwork Expansion Joint Replacement – Induction Draft (“ID”) Fans to Stack (\$710,667). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Karn Units 3 and 4;

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- BOP Capital tooling/valves/instrumentation (\$933,333). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Karn Units 3 and 4;
- Karn Units 3 and 4 - 250v Battery Bank Replacement (\$360,000). Replace the 250V battery with an equivalent and replace the charger with greater ampacity to handle full load if batteries die. New battery bank will make Karn Units 3 and 4 more reliable and safer to operate. New battery bank and battery charger will be in operation until the retirement of Karn Unit 3 and 4. New battery bank will improve availability of backup DC bearing and seal oil pumps. Karn Units 3 and 4 utilizes a 250-volt battery bank to run emergency bearing oil pumps & seal oil pumps in case of an emergency, like loss of AC power while the turbine is hot. The 250-volt Battery bank was installed in 2014. Design life of these batteries is approximately 10-12 years. The current batteries are rated for 910 amp hours. Based on the historical data, the 250-volt battery bank has been depleted/discharged a number of times. This has caused battery cells to operate/perform beyond their duty. A load test was conducted on this battery bank in 2022 and the results were marginal. A battery bank can serve the worst-case scenario load for approximately one hour only, which is less than the Company's recommended time for the turbine generator to come to stand still;
- Karn Unit 4 voltage regulator (\$400,000). The scope of this project is the installation of a "Digital Front End" upgrade to the GE Automatic Voltage Regulator on Karn Unit 4. The existing voltage regulator was installed around 2004 and was phased out of production in 2011. It became legacy equipment on March 1, 2021 and is no longer available. The software used to configure the existing system runs on Windows XP and is no longer patched or supported. The hardware will be upgraded from EX2100 to EX2100e architecture. This also includes ethernet switches, operator interface, GE project management, operation manuals, drawings, technical direction of installation and design package. Post maintenance testing and MOD-26 testing are also being included; and
- Five additional projects at Karn Units 3 and 4 totaling \$0.625 million which support safety, security, and reliability, with each project representing \$310,000 or less in capital expenditures. These projects include rewind of the Karn Unit 4 house service air compressor motor, replacement of the processors for the Karn Unit 3 automatic voltage regulator, Karn Units 3 and 4 tank farm storage tank heating line replacement, Karn Units 3 and 4 plant heating boilers, and replacement of the Karn Units 3 and 4 stack ladder fall protection system.

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1 **Q. What is the basis for the projected \$7.287 million capital investment in the projected**
2 **test period?**

3 A. The projected \$7.287 million capital investment in the projected test period will fund five
4 projects. Two of these projects are greater than \$1 million and are presented on Exhibit
5 A-12 (RTB-3), Schedule B-5.2, page 9, lines 18-19. The basis for these projects is
6 described below:

- 7 • Karn Unit 4 Replacement of Ductwork Insulation and Lagging (\$4,800,000).
8 The scope of this project is to replace the lagging and insulation on all the
9 ductwork from the building out to the stack. The existing lagging and insulation
10 needs to be removed, the underlying steel fixed as necessary, and new insulation
11 and lagging installed. The steel structure that the ductwork lagging is attached
12 to is severely corroded. This has allowed multiple random failures of the
13 lagging, resulting in a safety concern due to pieces of lagging falling to the
14 ground or becoming airborne during wind events; and
- 15 • Ductwork Expansion Joint Replacement – ID Fans to Stack (\$1,900,000). This
16 project will replace all expansion joints and entry doors between the ID Fans
17 and the stack. All expansion joints between the ID Fans and the Stack are
18 beyond their end of life and suspected to be severely degraded based upon the
19 condition of expansion joints found during the Karn Unit 3 Breaching project.
20 Failed expansion joints will need to be replaced to maintain environmental
21 compliance. This scope of work will make the ductwork air-tight again to
22 maintain environmental compliance.

23 The following projects are less than \$1 million, but are important to reliability:

- 24 • Capital tooling/valves/instrumentation (\$500,000). This project supports
25 capital expenditures for replacement of small valves, instrumentation, tools,
26 equipment, pumps, and motors at Karn Units 3 and 4 during the projected test
27 year; and
- 28 • Two additional projects at Karn Units 3 and 4 totaling \$0.087 million which
29 support reliability, with each project representing \$66,667 or less in capital
30 expenditures. These projects include overhaul of the Karn Unit 4 condenser
31 circulating water pumps and project closeout of Karn Units 3 and 4 sync wire
32 replacement.

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Zeeland Plant

Q. Please explain the Company's projected investment for the 14-month projected bridge period ending February 28, 2025 and projected test year ending February 28, 2026 for the Zeeland Plant.

A. The Company plans to invest \$48.518 million in the 14-month projected test period and \$50.929 million in the projected test year at the Zeeland Plant, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 29, columns (h) and (j), respectively. These capital expenditures will be facilitated, in part, by short outages in the spring and fall of the 14-month projected test period and the projected test year. The Company has an LTSA with GE that covers many reliability investments at the Zeeland Plant.

Q. What is the basis for the projected \$48.518 million capital investment in the 14-month projected bridge period?

A. The projected \$48.518 million capital investment will fund numerous safety, regulatory compliance, reliability, and infrastructure projects at the Zeeland Plant. There are five projects which are greater than \$1 million, and these projects are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 9 through 13. The basis for these projects is described below:

- Phase I Gas Turbine Advanced gas path replacement and axial fuel staging (\$20,356,250). This project spans the projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Zeeland Plant;
- Zeeland Plant LTSA (\$9,520,000). This project spans the projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Zeeland Plant;
- Zeeland Unit 5 GSU Rewind (\$5,546,538). The scope of this project will remove the failed Zeeland Unit 5 GSU transformer and send it out for rewind and overhaul to support long-term reliable operation. This project also installs a leased GSU transformer. The Zeeland Unit 5 GSU Transformer, which

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1 outputs electricity from the generator to the grid, was showing signs of
2 imminent failure as indicated by hydrocarbon gasses being continuously
3 generated at rates above Institute of Electrical and Electronics Engineers (IEEE)
4 recommended levels. The time to failure could not be predicted and could have
5 been catastrophic in nature. Previous intrusive internal inspection and testing
6 work in fall of 2022 was able to identify and replace some degraded parts but
7 ultimately not able to locate the source of gas generation;

- 8 • Zeeland Plant HRSG Casing Replacement (\$2,097,620). The HRSG is
9 designed to recover and recycle heat energy from a gas turbine exhaust.
10 A HRSG produces steam that is used to drive a steam turbine. During recent
11 inspections of the HRSGs at the Zeeland Plant, extensive outer casing corrosion
12 has been identified in particular sections of the units. This condition creates the
13 risk of the studs, which hold on the insulation and liner panels, breaking loose
14 and liberating both insulation and liner sheets. The insulation then blows
15 downstream and fouls the HRSG tubes, requiring the unit to be shut down and
16 cleaned, then subsequent casing, insulation, and liner repairs. The affected
17 areas of casing need to be cut out and replaced with new casing; and
- 18 • Zeeland Plant LTSA supplementals not included in contract (\$3,925,000). This
19 project spans the projected bridge period and the projected test year, and its
20 basis is included in my discussion of projected test year capital projects for the
21 Zeeland Plant.

22 The following projects are less than \$1 million but are important to regulatory compliance
23 and reliability:

- 24 • Main Steam Non-return Valve Replacement (\$705,309). The scope of this
25 project is to replace both main steam check valves. During inspections in the
26 Fall 2018 outage, cracking was noted on both of the main steam stop-check
27 valve body internals. With continued plant operation, the cracks are expected
28 to continue to grow, potentially extending through the valve seat, making the
29 valve unable to seal completely. The cracks can also grow to a through-wall
30 crack, resulting in a steam leak. This cracking is a known issue with these types
31 of valves, and is driven by expansion differentials primarily on startup and
32 shutdown. This cracking had initially been noted during a pipe borescope
33 inspection in 2011;
- 34 • Zeeland - Purchase of Site Spare GSU Transformer (\$589,607). This project
35 spans the projected bridge period and the projected test year, and its basis is
36 included in my discussion of projected test year capital projects for the Zeeland
37 Plant;
- 38 • 199 and 499 345kV Breaker Replacement (\$623,483). The scope of this project
39 is to replace the 199 and 499 circuit breakers with a type which does not exhibit
40 the failure modes exhibited by the existing design. The existing breakers have
41 a critical design flaw such that an individual pole or poles may not latch open

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1 when required. The pole's failure to latch open has the potential to result in lost
2 generation, loss of power to the entire Zeeland Substation, and/or equipment
3 damage;

- 4 • Site Commons Road Resurfacing (\$554,167). This project spans the projected
5 bridge period and the projected test year, and its basis is included in my
6 discussion of projected test year capital projects for the Zeeland Plant;
- 7 • Gas Turbine Inlet Filters Replacement (\$390,000). The scope of this project is
8 to replace canister filters. The filters are required to be replaced every five years
9 and must be accomplished during an outage. The purpose of the project is to
10 maintain the integrity of the filters to prevent material ingress to the turbines;
- 11 • ZGS – GE DCS Evergreen (\$600,000). The scope of this project is to upgrade
12 the Zeeland Plant Turbine Controls DCS with the latest version available at the
13 time of the project. The system is currently running on a VMware virtualized
14 system which was installed in 2020. This Evergreen will only replace the
15 existing GE Software, Operating Systems, and miscellaneous upgrades. This
16 project will allow the latest versions of control software and operating systems
17 to be used for reliable operation and control of the generating units. The latest
18 feature enhancements are also available for operation. This will also allow the
19 latest patches to be applied by the cyber security Emerson PWCS application.
20 The DCS must be upgraded at a four-to-five-year upgrade cycle to maintain
21 reliable control and recent operating systems and applications that are patchable.
22 The vendor life cycle for DCS versions is generally five years. After five years
23 they enter a retired state and are no longer patched. Microsoft Operating Systems
24 are on a limited life basis, and they reach the end of "extended support" and no
25 longer get security patches;
- 26 • ZGS – 299 345kV Breaker Replacement (\$510,000). The scope of this project
27 is to replace the 299 circuit breaker with a type which does not exhibit the
28 failure modes exhibited by the existing design. The existing breaker has a
29 critical design flaw such that an individual pole or poles may not latch open
30 when required. The pole's failure to latch open has the potential to result in lost
31 generation, loss of power to the entire Zeeland substation, and/or equipment
32 damage;
- 33 • Zeeland Plant Base Outage Capital (\$482,555). Base outage capital covers the
34 replacement parts and issues found during turbine/generator inspections and the
35 major discovery issues found during annual unit outages; and
- 36 • Seventeen additional projects at the Zeeland Plant totaling \$2.617 million
37 supporting safety, reliability, regulatory compliance, infrastructure, and
38 operations, with each project representing less than \$337,200 or less in
39 expenditures. These projects include Install Combustion Turbine Overspeed
40 Software, Phase 2 599 and 699 345kV Breaker Replacement, Zeeland
41 combined cycle GT2A GT2B Air Filter Replacement, MarkVIe Controller
42 Replacement Project, 480V Circuit Breaker Coordination System Replacement,

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CT Autotune Software Replacement, boiler feedwater pump, and small tools, pumps, motors, valves, and instrumentation.

Q. What is the basis for the projected \$50.929 million capital investment in the projected test year?

A. The projected \$50.929 million capital investment in the projected test year will fund numerous safety, regulatory compliance, reliability, and infrastructure projects at the Zeeland Plant. There are six projects which are greater than \$1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 12-17. The basis for these projects is described below:

- Zeeland Plant LTSA (\$8,181,333). This is the capital portion for negotiated services that cover the planned normal maintenance of each unit based on its equivalent operating factor fired hours. The planned maintenance includes the following support services (OEM on-site/off-site technical support, engineering, and labor). Typical activities include borescope inspections, capital repairs, unit tuning, addressing service bulletin requirements, and on-site inspections. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected pre-mature failures of the equipment. This will help minimize ROR and it will optimize customer value for the site. Normal maintenance will ensure the Company continues reliable operation of the units;
- Zeeland Plant LTSA supplementals not included in contract (\$4,275,000). The LTSA supplemental work is defined as the work that is not covered under normal planned maintenance in the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items that need to be addressed are labor and material to replace the following: blading, combustion cans, ignitors, vanes/bushings, and any components on the compressor end as the compressor is not covered under the LTSA;
- Zeeland Site Spare GSU Transformer (\$6,449,004). The scope of this project is the procurement of a spare GSU transformer for the Zeeland site. The Zeeland Plant consists of four gas turbine powered plants and one steam turbine powered plant. The units transmit their power to the grid via GSU transformers. If a GSU were to fail, then the associated turbine would not be able to transmit power and would not be able to generate energy and capacity

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1 market value for Consumers Energy and its customers. For the Zeeland
2 combined cycle plant, the combustion turbine requires the operation of the
3 steam turbine, therefore the loss of the steam turbine's GSU transformer would
4 effectively limit operation of two connected combustion turbine units. The
5 lead time for a GSU transformer is currently three-to-four years and spare units
6 at other facilities are not viable replacements due to compatibility and
7 installation challenges. This project would purchase a spare GSU transformer
8 that is sized to be able to replace any of the existing transformers on site and
9 develop redundancy for any minor power upgrades in the future. As previously
10 discussed, the GSU transformer for Zeeland Unit 1 has failed and is being sent
11 out for rewind;

- 12 • Phase I Gas Turbine Advanced gas path replacement and axial fuel staging
13 (\$25,743,740). The scheduled Major Inspection outages in 2025 for the Phase 1
14 gas turbines at Zeeland Generating Station present an ideal time for substantial
15 technological advancements. This project proposes the integration of Advanced
16 Gas Path ("AGP") and Axial Fuel Staging ("AFS") technologies during these
17 outages, aimed at boosting turbine performance and operational flexibility.
18 A more detailed analysis of this project is presented in Exhibit A-46 (RTB-7):
19 Zeeland Phase 1 Gas Turbine upgrades;
- 20 • Generator Rewinds (\$2,174,167). There are multiple Technical Information
21 Letters (Bulletins) from the OEM (GE) involving the brazed connections under
22 the retaining rings that need to be addressed as well as multiple turn shorts
23 potentially evident by the OEM 2021 health assessments for Zeeland Units 3
24 and 4. The impacts of turn shorts include: uneven heating of the rotor which
25 will lead to increased seismic vibrations that can create multiple failure
26 scenarios for a field and possible induced rotor bow, higher field current
27 required to match original design which can result in higher heating effects and
28 escalated failure modes, and damage to the retaining rings which will further
29 escalate the vibrational issues. During the major overhaul, the generator rotors
30 will be removed and replaced/rewound, correcting the issue with the
31 connections and shorted turn issue, allowing the units to run to the anticipated
32 end of life; and
- 33 • Phase II Turbine Replacements (\$1,884,167). The scope of this project replaces
34 the existing rotor with a new rotor, giving another 144,000 hours of operation
35 which would enable operation until the next rotor replacement out to
36 approximately the year 2045. Also included in this scope is new compressor
37 stator vanes due to the compressor being 20 years old; the best way to restore
38 the compressor to like-new condition is to replace the stationaries when the
39 blades will already be replaced. Lastly, the exhaust frame will be upgraded to
40 a robust exhaust frame due to reliability issues over the years, and the rotor
41 replacement being an appropriate time to replace the exhaust frame.

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Several other critical projects which are less than \$1 million but are important to reliability and infrastructure include:

- Zeeland combined cycle SCR Catalyst Replacement (\$417,500). The scope of this project is to replace the SCR catalyst to maintain NOx reduction on gas turbine emissions;
- Site Commons Road Resurfacing (\$395,833). The scope of this project is to perform continued resurfacing of site roads. Several roads require widening to ensure safe 2-way vehicle travel (e.g. road behind substation). Roads/driveways on site require continuous maintenance. The objective of the project is to ensure roadways are safe for both vehicle and pedestrian travel;
- Zeeland Plant Base Outage Capital (\$424,444). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during unit outages; and
- Nine additional projects at the Zeeland Plant totaling \$0.984 million support reliability and operations, with each project representing \$241,667 or less in expenditures. These projects include Unit 5 Battery Replacement, Phase II Unit 3 and 4 battery monitoring system, compressed air system replacement, boiler feedwater pump replacement, and small pumps, motors, valve, instrumentation, tools, and equipment.

Jackson Plant

Q. Please explain the Company's projected investment for the 14-month bridge period ending February 28, 2025 and test year ending February 28, 2026 for the Jackson Plant.

A. The Company plans to invest \$19.130 million in the 14-month projected bridge period and \$14.965 million in the projected test year at the Jackson Plant, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 36, columns (h) and (j), respectively. This will be facilitated by short outages in the fall of 2024 and 2025. The Company has a LTSA with GE to cover many reliability issues at the Jackson Plant.

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1 **Q. What is the basis for the projected \$19.130 million capital investment in the 14-month**
2 **projected bridge period?**

3 A. The projected \$19.130 million capital investment in the 14-month projected bridge period
4 will fund numerous safety, regulatory compliance, reliability, and infrastructure projects.
5 There are two projects which are greater than \$1 million, and they are presented on Exhibit
6 A-12 (RTB-3), Schedule B-5.2, page 8, lines 7-8. The basis for these projects is described
7 below:

- 8 • Jackson Plant LTSA (\$12,337,500). This project spans the 14-month projected
9 bridge period and the projected test year, and its basis is included in my
10 discussion of projected test year capital projects for the Jackson Plant; and
- 11 • Jackson Plant LTSA Extra Work (\$2,908,333). This project spans the
12 14-month projected bridge period and the projected test year, and its basis is
13 included in my discussion of projected test year capital projects for the Jackson
14 Plant.

15 Several other critical projects which are less than \$1 million but are important to reliability
16 and infrastructure include:

- 17 • Feedwater Desuperheater Valve Replacement (\$831,433). The scope of this
18 project is to install feedwater control valves and separate lance spray nozzle
19 assemblies that spray small amounts of water into steam flow continuously.
20 The HRSG 1-6 superheat ("SH") Steam Desuperheater Feedwater valves have
21 had very short life spans since original construction. There are several issues
22 that cause the valves to wear out quickly. The valves inherently cycle frequently
23 open and closed due to the boiler running close to high pressure ("HP") Steam
24 Outlet temperature setpoint at gas turbine baseload, without duct firing. This
25 has been reduced recently by a study completed by engineering and GE to allow
26 the HP Steam temperature to be increased from the original 750 degrees
27 Fahrenheit up to 770 degrees Fahrenheit. This change did cause the valves to
28 cycle open/close less frequently, but it did not result in a substantial
29 improvement in valve life. The brunt of the wear is absorbed by the HP FW
30 Autoblock valve, which when it begins to leak by, causes the SH Steam
31 temperature to fall. The HP FW Control Valve wears out quickly as well.
32 Typically, when this occurs the leak by accelerates quickly to the point which
33 the manual HP FW isolation valve upstream must be closed when the unit is
34 not duct firing in order to maintain adequate superheated steam temperature;

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- LM6000 Beckwith Relay Replacement (\$391,667). The scope of this project seeks to replace the LM6000 Generator Protective Relays with direct replacement relay upgrades and install test facilities in a pre-planned fashion. This will protect the generation assets and avoid issues with the obsolescence of the existing equipment. Jackson Units 1 through 6 are currently protected with Beckwith M3420 Relays that are obsolete. The long lead time replacement M-3425A relays have been purchased, and are awaiting installation.

In addition to being obsolete, the existing relays have limited, or no means for communication, fault analysis, troubleshooting, and event recording following an electric fault event. The current relays also do not have external test facilities for periodic maintenance. Because of this, the relays need to be un-wired to test, and then rewired. This increases maintenance time, as well as exposes the plant to unplanned operations due to human error;

- Base Outage Capital (\$350,000). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Jackson Plant;

- Jackson Site 480V Breaker (WavePro) Replacement (\$267,000). The 480V circuit breakers each have a small control box that senses the amount of current thru the breaker and trips the breaker for a fault. These trip modules have electronic components normally expected to last 10 years, and some are presently failing after 20 years of service. Since these trip modules are no longer made, a failure requires complete replacement of the module and current sensors at a qualified breaker repair shop. The scope of this project is to replace all 30 trip modules;

- Units 1-6 LM HP Start-up Vent Silencer Replacement (\$248,000). The degradation of the existing LM HP Start-Up Vent Silencers (original to plant) has resulted in exceeding the noise level limitations set forth in ST-001, Standard Technical and Site Data Specification. The specification states that the equipment shall not exceed 90 dBA when measured three feet from vent silencer opening at 90 degrees to the flow. The noise levels are disruptive to the surrounding neighborhood in addition to plant personnel. The replacement of three silencers will reduce the noise of current silencers, prevent additional excessive noise for plant personnel (OSHA) and surrounding community safety, and proactively avoid risk of violating city ordinances;

- JGS – Low Quality Sump Piping Replacement (\$256,535). The Jackson Plant has three sump pits to deal with wastewater throughout the plant. One of these sump pits is called the water treatment low-quality (“LQ”) sump, one the main low-quality sump, and one is the high-quality (“HQ”) sump. The water treatment LQ sump deals with most of the wastewater that comes from the plant including reverse osmosis backwash discharge, floor drains and miscellaneous sources. The main LQ sump takes transformer secondary containment drains. The HQ sump handles blow down condensate from the running units. Each

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1 sump pit has two pumps that operate off a multi-float switch level indicator.
2 The level indicators are reaching end of life. The water treatment LQ pumps
3 have a mean time between failures of about one year. The HQ sumps were
4 upgraded in 2019 with no failures at this time. The failures on the water
5 treatment sumps are due to failed bearings, worn impellers, volutes, and
6 casings. There is a large amount of dirt, oil, and other debris that get into the
7 water treatment LQ sump leading to wear of pump components and bearing
8 failures. The scope of this project is to replace the two sump pumps in the water
9 treatment LQ sump and the level indication on both LQ sumps. It is
10 recommended to install pumps with upgraded wear materials to help with the
11 erosion issue and install sealed greased bearings. The level transmitters are also
12 beginning to fail as the switches do not always actuate when they are supposed
13 to. The level transmitters will be replaced with radar level transmitters. The
14 sumps are locally controlled with an audible alarm. This project would also
15 bring control and level indication into the DCS for the sump;

- 16 • JGS NOx Umbilical Replacements (\$300,728). The scope of this project is to
17 replace the heated sample line (umbilical) on Jackson Units 1 through 5 and 7
18 from the analyzer to the stack probe. The Continuous Emissions Monitoring
19 System (“CEMS”) and associated umbilicals have been in service since 2002.
20 As a result of the heat trace failure on the LM6 umbilical in 2020 and the visual
21 condition of the polyurethane jacket, the remaining umbilicals were inspected.
22 Similar cracking and poor installation practices were observed. To avoid unit
23 downtime in the future, the Company determined that a project should be
24 initiated to replace the remaining units’ umbilicals. A three-year
25 implementation plan, replacing two umbilicals per year, is proposed to mitigate
26 risk. The new umbilicals will utilize a PVC jacket that is more resistant to
27 degradation and chemical attack. Post maintenance testing will be required
28 upon replacement including a relative accuracy test audit (“RATA”) to recertify
29 the CEMS. The combined-cycle combustion turbines at Jackson are subject to
30 specific NOx emission limits and monitoring requirements originating from
31 several environmental rules. For purposes of demonstrating compliance with
32 the NOx emission limits, JGS relies upon CEMS for each unit;

- 33 • Jackson Combustion Turbine Inlet Canister Filter Replacement (\$230,000).
34 The Jackson Plant is comprised of nine generating units. Jackson Units 1
35 through 7 draw combustion air in through a filter house which has integrated
36 filters to prevent dust, dirt, and debris from being pulled into the compressor
37 section of the turbine. The canister filters require periodic replacement to
38 maintain proper air flow to the engine. Over time the filters plug and reduce
39 the efficiency of the combustion turbine. If air flow is restricted enough, the
40 engine can stall due to lack of sufficient air causing catastrophic failure; and

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- Twelve additional projects at the Jackson Plant totaling \$1.009 million, with each individual project representing \$262,500 or less in expenditures. These projects include LM1-6 VIGV (variable inlet guide vane) Project, Major Motor and Pump Replacements, site small capital, DCS Evergreen replacement, and LM1-6 Steam injection trap replacements.

Q. What is the basis for the projected \$14.965 million capital investment in the projected test year?

A. The projected \$14.965 million capital investment in the projected test year will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There is one project which is greater than \$1 million, and it is presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, line 11. The basis for this project is described below:

- Jackson Plant LTSA (\$11,116,875). This is the capital portion for negotiated services that cover the planned normal maintenance of each unit based on its equivalent operating factor fired hours. The planned maintenance includes the following support services: OEM on-site/off-site technical support, engineering, and labor. Typical activities include borescope inspections, capital repairs, unit tuning, addressing service bulletin requirements, and on-site inspections. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected pre-mature failures of the equipment. This will help maximize availability and, as a result, optimize customer value for the site. Normal maintenance will ensure the Company continues reliable operation of the units.

Several other critical projects which are less than \$1 million but are important to reliability and infrastructure include:

- Jackson Plant LTSA Supplemental Work (\$350,000). The LTSA supplemental work is defined as the work that is not covered under normal planned maintenance in the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items that need to be addressed are labor and material to replace the following: blading, combustion cans, ignitors, vanes/bushings, and any components on the compressor end as the compressor is not covered under the LTSA;

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- 1 • Base Outage Capital (\$300,000). Base outage capital covers the replacement
2 parts and issues found during turbine/generator inspections and the major
3 discovery issues found during annual unit outages;
- 4 • JLM1-6 Variable Inlet Guide Vane (“VIGV”) Project (\$900,000). This project
5 will install new VIGV systems on six LM6000PC engines at the Jackson Plant.
6 The seventh LM6000PC engine has a partial installation already, and the project
7 will complete the VIGV system for this engine. For LM6000PC SPRINT gas
8 turbines, which the Jackson Plant has, the VIGV upgrade is expected to yield a
9 significant fuel efficiency improvement at part power. The average fuel
10 efficiency improvement at 70% of maximum power is greater than 2%. The
11 VIGV also helps minimize variable bypass valve (“VBV”) flow and pressure
12 levels, thereby reducing associated flow noise. The VIGV system improves
13 performance for both simple cycle and heat-recovery cycles when operating at
14 less than full load;
- 15 • GSU Transformer Site Spare (\$833,333). This project provides Jackson with a
16 reliable spare GSU to which it currently does not have access. The main
17 transformers (GSUs) are a single point of failure to delivering power from the
18 generators to the grid. For failure of one main transformer, lost generation
19 would be 47 MW to 104 MW, depending on which generator(s) are connected.
20 The lead time for a new transformer is three-to-four years, since every
21 transformer of this size is custom built, and a large quantity of special raw
22 materials is required. The Company’s spare transformers located at Campbell,
23 Karn, Lake winds, and Crosswinds do not have the correct voltage
24 (138kV-13.2kV-13.2kV) or correct winding configuration (WYE-DELTA) to
25 function at Jackson so they cannot be considered for use as spares;
- 26 • DCS Evergreen replacement (\$666,667). This project replaces the GE DCS
27 with the latest version available at the time of the project. The system is
28 currently running on a VMware virtualized system. The system was installed
29 in 2020. This Evergreen will only replace the existing GE Software, Operating
30 Systems, and miscellaneous upgrades. The controller drops and rack-mounted
31 servers will not be replaced for this upgrade. (Standard practice is to replace
32 virtualized system hardware every eight years to reduce costs.) The DCS must
33 be upgraded at a four-to-five-year upgrade cycle to maintain reliable control
34 and recent operating systems and applications that are patchable. Vendor life
35 cycle for DCS versions is generally a five-year cycle. After five years they
36 enter a retired state and are no longer patched. Microsoft Operating Systems
37 (O/S) are on a limited life basis, and they reach the end of “extended support”
38 and no longer get security patches. Corporate policies require all systems to be
39 patched regularly along with Anti-Virus updates; and
- 40 • Fourteen additional projects at Jackson Plant totaling \$1.098 million, with each
41 individual project representing \$225,000 or less in expenditures. These projects
42 include (13476) JGS - LM1-6 Steam injection trap replacements, generator

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breaker replacements, breaker relay replacements, major motor and pump overhauls, and small valves, instrumentation, tools, equipment, pumps, and motors.

HYDRO UNITS

Q. Please explain the Company's projected capital expenditures for the 14-month projected bridge period ending February 28, 2025 and the projected test year ending February 28, 2026 for the Hydro Units.

A. The Company plans to invest \$42.376 million in the 14-month bridge period and \$92.258 million in the projected test year in the Hydro Units, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 3, line 64, columns (h) and (j), respectively.

Q. What is the basis for the projected \$42.376 million capital investment in the 14-month projected bridge period?

A. The projected \$42.376 million capital investment will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are ten projects which are greater than \$1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 20 through 29. The basis for these projects is described in the direct testimony of Company witness Monroe.

Q. What is the basis for the projected \$92.258 million capital investment in the projected test year?

A. The projected \$92.258 million capital investment in the projected test year will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are 13 projects which are greater than \$1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 21 through 33. The basis for these projects is described in the direct testimony of Company witness Monroe.

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LPS

Q. Please explain the Company's projected capital expenditures for the 14-month projected bridge period ending February 28, 2025 and the projected test year ending February 28, 2026 for the LPS.

A. The Company plans to invest \$10.279 million in the 14-month projected bridge period and \$15.587 million in the projected test year in the LPS, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 3, line 71, columns (h) and (j), respectively. These capital investments will be implemented in periodic outages in the spring of 2024 and 2025. It is important to note that none of these investments are associated with resolving the Toshiba defects. Those investments are being recorded to a regulatory asset pursuant to the MPSC's May 18, 2023 Order in Case No. U-21310.

Q. What is the basis for the projected \$10.279 million capital investment in the 14-month projected bridge period?

A. The projected \$10.279 million capital investment in the 14-month projected bridge period will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are two projects which are greater than \$1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 30-31. The basis for those projects is described below:

- Ludington Units 1 through 6 DCS Control Relay Replacement (\$1,648,169). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;
- LPS – Lower Penstock Expansion Joint (“LPEJ”) Chamber Waterstop replacement (\$2,716,000). The scope of this project is replacement of the LPEJ waterstop and potentially dewatering the surrounding groundwater. The engineering study was performed in 2020 at a cost of \$0.404 million and project

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1 implementation began in 2021 and is planned to be completed in 2024. In 2021,
2 the engineering was completed, and the design was approved by FERC; and

- 3
- 4 • The LPEJ Chambers enclose the penstock expansion joints in concrete
5 chambers. The penstock expansion joints allow penstock expansion with
6 seasonal temperature changes. The waterstop is a membrane intended to
7 prevent groundwater from leaking into the LPEJ. Some joints have been
8 leaking since shortly following plant construction. In February 2017, a
9 depression was discovered upstream of Ludington Unit 3, which was caused by
10 transport of soil into the chamber by inflowing groundwater. Historically,
11 Consumers Energy sealed the leaks into the LPEJs using hydrophobic
12 polyurethane grout. However, the waterstops are at the end of their expected
13 life and grouting is no longer an effective solution. Failure to remedy the in
14 leakage is a threat to generation because if the settlement of the chambers
15 reaches a certain threshold, the generation unit(s) will remain in a forced outage
16 until the LPEJ chamber(s) can be stabilized. The implementation of this project
17 reduces current risk of a potential failure mode and supports Ludington unit
generation well into the relicensing period.

18 The following projects are less than \$1 million but are important to regulatory compliance
19 and reliability:

- 20
- 21 • Replace Barrier Net Panels (\$679,115). This project spans the 14-month
22 projected bridge period and the projected test year, and its basis is included in
my discussion of the projected test year capital projects for Ludington;
 - 23 • Replace 480V Dike Load Centers (\$993,800). This project spans the 14-month
24 projected bridge period and the projected test year, and its basis is included in
25 my discussion of the projected test year capital projects for Ludington;
 - 26 • LPS Oil Water Separator Replacement (\$780,249). This project spans the
27 14-month projected bridge period and the projected test year, and its basis is
28 included in my discussion of the projected test year capital projects for
29 Ludington;
 - 30 • LPS Intake Gate and Gate House Mechanical Replacement (\$409,099). This
31 project spans the 14-month projected bridge period and the projected test year,
32 and its basis is included in my discussion of the projected test year capital
33 projects for Ludington;
 - 34 • Governor Replacement (\$474,167). This project spans the 14-month projected
35 bridge period and the projected test year, and its basis is included in my
36 discussion of the projected test year capital projects for Ludington;
 - 37 • Ludington All Unit Critical Valve and Actuator Replacement (\$565,000). The
38 scope of this project is to replace valves, actuators, and associated equipment

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critical to unit specific operation. There are also certain valves that provide routine tagging points that provide worker protection. Many of these valves have known issues such as damaged seals (leakage when the valve is closed), leaking packing (cannot be tightened further), and severely corroded valve stem extensions. Additionally, many of these valves are paired with pneumatic actuators which have also been identified with operational issues. Most of the handwheels are broken and do not provide a secondary means of operating the valve if the pneumatic actuator were to fail. This could present a particularly dangerous situation if a pipe were to fail. Additionally, damage to the actuator linkages and slides have been noted in previous inspections. The linkage damage has introduced play or slop into the mechanism which can be seen during operation and will lead to eventual failure of the mechanism; and

- Twenty-two additional projects at LPS totaling \$2.014 million, with each individual project representing \$256,896 or less in expenditures. These projects include LPS DAC 1 and 2 replacement, subdrainage and unwatering sump pump controls and pump replacement, CO2 Fire Protection System Replacement Centralized Grease System Replacement, and small tools, pumps, motors, valves, and instrumentation.

Q. What is the basis for the projected \$15.587 million capital investment in the projected test year?

A. The projected \$15.587 million capital investment in the projected test year will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are five projects which are greater than \$1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 34 through 38. The basis for these projects is described below:

- DCS Control Relay Replacement (\$4,771,901). The scope of this project is to replace and eliminate worn and less reliable control relays with new electronic input/output modules and new relays where needed. The number of hardware control relays will be reduced due to the “control” being performed in logic instead of “hardwired” circuits. This will increase reliability and reduce outages and unit derates. Common control and monitoring of system equipment allows operation of the equipment from the Human Machine Interface (“HMI”) graphics and keeps the operator focused on one system instead of monitoring several systems from several areas of the control room.

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1 The LPS units are controlled by using the original hardwired
2 electromechanical relay control system to operate the units. A modern DCS
3 system will provide the LPS units with improved diagnostic and
4 troubleshooting capabilities. The DCS system will make it easier to automate
5 any updates of equipment and systems that are integrated with the unit
6 operation, and to implement, test, and verify changes to operating criteria.
7 Furthermore, the modern DCS has the capability to perform these functions at
8 a lower cost and requiring less time.

9 The existing relay control system is based on electromechanical devices that
10 wear and become less reliable over time. The relay contacts wear, and increased
11 resistance can cause intermittent failures. Troubleshooting these issues are
12 difficult and time-consuming. The relay control system will not last until end
13 of life of the units and need to be upgraded to a modern DCS control system.
14 The Emerson Ovation DCS infrastructure was installed as part of the 2019-2021
15 Data Acquisition System (“DAS”), Annunciator, PLC, and Sequence of Events
16 recorder replacement project. This provides a common historian, HMI graphics
17 control, alarm management system and modern control system for reliable
18 efficient unit operation. The DAS project provides the infrastructure to build
19 upon for full site/unit control at LPS;

- 20 • Replace 480V DLCs (\$1,566,400). The scope of this project is the replacement
21 of the 20 480V DLCs over a six-year period that began in 2020 at a capital
22 expenditure amount of \$0.671 million. The DLCs are original plant equipment
23 and suffer from corrosion and deterioration. The primary purpose of the DLCs
24 is to distribute power to 193 dike drain pumps and 34 pumping relief wells
25 located around the reservoir. The purpose of the dike drain pumps is to keep
26 the upstream face of the dike in a drained condition and to protect the asphalt
27 liner from damage due to differential pressure. The purpose of the pumping
28 relief wells is to keep groundwater at pre-construction levels, thereby
29 minimizing the likelihood of a downstream slope failure. Replacement of the
30 DLCs over a six-year period will provide high electrical system reliability and
31 ensure FERC compliance;
- 32 • LPS Commons Station Power Transformer (“SPT”) Life Cycle Management
33 (\$1,150,000). The scope of this project is to procure and replace all six SPTs
34 with new to suit size and configuration in current LPS footprint. The SPTs are
35 original to the site, and are in service outdoors on the LPS roof. The benefits
36 of the project are restoration of system voltage to rated, increase site equipment
37 life span, extension of life expectancy to that of site, enablement of the ability
38 to perform routine maintenance without risk of damage, and reduction in the
39 probability of failure and the associated risk of not having a spare;

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- Governor Replacement (\$1,915,833). The scope of this project is to contract with a specialized vendor to inspect, repair as required, and modernize the unit governors. The LPS unit governors have not been overhauled in approximately 15 years and, as a result, show signs of significant wear; and
- Intake Gate and Gate House Mechanical Replacement (\$1,666,014). The LPS intake gates and associated hoist equipment are the primary form of mechanical protection for the LPS units. Their purpose is to isolate the stored energy from the reservoir's water against each unit's penstock when dewatering or during emergency conditions such as a penstock rupture or governor failure. Reliable operation of this system is critical to minimize damages from a unit run away condition or a penstock failure, acting as a last effort to control unit overspeed. The mechanical system of the intake gate hoist is all original (circa 1971) and recent OEM inspection revealed that its condition is poor and in need of refurbishment. Updates and repairs are required to support the current facility license extension of 2069. The electrical control system is well past its design service life. This outdated technology is obsolete, and certain critical components are no longer available for spare parts. Modern technology offers more reliable options that would give the system an additional 30 years of service. The head gate hoist is enclosed in a steel structure on top of the intake (head gate enclosure). The head gate hoist enclosures are original to the plant and have rusted out in many places. Significant corrosion has been noted on the steel frame, the connections, and the beams. These enclosures need to be replaced as they are beyond a repair option.

The following projects are less than \$1 million but are important to regulatory compliance and reliability:

- LPS Oil Water Separator ("OWS") Replacement (\$438,746). The scope of work for this project is to install a separate, parallel train OWS to that of the plant's existing OWS, modify existing support systems (station sump, station sump pumps, and metering devices) to support new OWS, and retrofit the existing OWS to improve oil separability. This will allow temporary use of the modified original OWS while servicing the anticipated new one as to not impact unit availability. The project is being performed in order to comply with requirements for effluent discharge during all modes of operation and process upset conditions. The failure to perform this project would likely lead to additional releases in excess of the National Pollutant Discharge Elimination System permit requirements throughout the facility's lifecycle. Although not quantified, cost for these releases could be significant in terms of potential fines, reputational damage, cleanup costs, and other intangibles;
- Centralized Grease System Replacement (\$303,604). The scope of this project is to replace end of service life components such as pumps, distributing blocks, and solenoid valves, and to modernize the control system to a self-diagnostic

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PLC system. The current electro-pneumatic grease system(s) that service certain bushings are past their service life and of questionable reliability (original plant functionally equipment);

- Replace Barrier Net Panels (\$829,725). The panels are a regulatory required system to minimize fish entrainment. The panel replacements are primarily time based. LPS has extensive operating experience with these panels, which helps determine when a replacement is required; and
- Nineteen additional projects at Ludington totaling \$2.944 million, with each individual project representing \$298,332 or less in capital expenditures. These projects include north fabrication shop storage mezzanine and humidity control, pony motor isolation switch life cycle project, all unit critical valve and actuator replacement, cathodic protection system replacement, main transformer bank isophase cooling blower replacement, subdrainage and unwatering sump pump controls and pump replacement, flow transmitter replacement, and small tools, pumps, motors, valves, and instrumentation.

ADMINISTRATIVE AND OTHER

Q. Please explain the Company's projected capital expenditures for the 14-month projected bridge period ending February 28, 2025 and the projected test year ending February 28, 2026 for Administrative and Other.

A. The Company plans to invest \$2.795 million in the 14-month projected bridge period and \$3.096 million in the projected test year in Administrative and Other, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 3, line 78, columns (h) and (j), respectively.

Q. What is the basis for the projected \$2.795 million capital investment in the 14-month projected bridge period for Administrative and Other?

A. The projected \$2.795 million capital investment will support several projects during the 14-month bridge period. The basis for these projects is described below:

- Generation Operations – Ovation security center replacement evergreen (\$300,000). The Generation control systems cyber security tool that is used for control system security is the Emerson PWCS. This tool is comprised of multiple cyber security products used in the industry today. Because of the quickly changing technology and techniques used by hackers, the cyber security tools require an increased update cycle of two to three years. The Karn site has been using the PWCS tool for 10 years. It was last upgraded in 2017. To

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support the latest version of Ovation DCS, the PWCS system must be upgraded. This replacement will support the protection of multiple components of the control system across multiple sites including Karn Units 3 and 4, Campbell, Jackson, Zeeland, and Ludington. The tools included are:

- Anti-Virus;
- Malware Prevention with Application Control;
- Patch Management;
- Device Control;
- Rogue System Detection;
- System Backup and Recovery;
- Security Incident and Event Manager; and
- Change Management.

- Fleet - Move the machine shop (\$616,667). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Administrative and Other;

- Transformation - Enterprise Project Management Information System (\$850,010). The scope of this project is the continuing support of Unifier, the Company's project management information system ("PMIS"). During the bridge period, the Company is implementing a major upgrade to Unifier and Primavera P6 ("P6"). Specifically, the Company is moving from version 19.12 to 22.12 for both Unifier and P6. The upgrade reflects three years of upgrades from oracle which includes various enhancements. The scope of the project also includes the February 2024 procurement of 350 additional licenses to support the continued user growth the Company expects from the new functionality in the upgrade. The increased user growth includes expansion of the products to additional engineering personnel, some project management personnel, and some vendors. In addition to the upgrade and procurement of additional licenses, the Company has continued its quarterly implementation of continuous-improvement updates (new functionality that Company users identify) that include the creation and or configuration of new reporting and business processes; and

- Seven additional projects totaling \$1.028 for generation cyber security, ovation cyber security, laptop and capital business tool purchases for Generation Engineering, Electric Supply, Environmental Services, Lab Services, Business Services, and Enterprise Project Management.

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1 **Q. What is the basis for the projected \$3.096 million capital investment in the projected**
2 **test year?**

3 A. The projected \$3.096 million capital investment in the projected test year will fund various
4 projects. One of these projects is greater than \$1 million, and is presented on Exhibit A-12
5 (RTB-3), Schedule B-5.2, page 9, line 20. The basis for these projects is described below:

- 6 • Fleet - Move the machine shop (\$2,100,000). The scope of this project is to
7 move the machine shop. The existing machine shop is located at the Campbell
8 site and with the closure of the Campbell units on May 31, 2025, the Company
9 will likely have to relocate the existing machine shop. Options for the project
10 include (1) doing nothing and going to third parties for parts which will impact
11 both cost and timing of delivery, (2) purchasing another machine shop,
12 (3) section off the training center at Campbell and move the machine shop to
13 that building, and (4) Building a machine shop in a centralized location to better
14 service all generation sites.

15 The machine shop has proven its financial viability, with a positive variance
16 of \$67,978 in 2023. It has consistently demonstrated the ability to generate
17 revenue exceeding operational costs, a trend expected to continue based on
18 projections. The shop's ability to quickly turn around projects and fabricate
19 parts faster than external vendors has led to substantial savings, particularly in
20 replacement power costs, estimated at \$300k annually; and

- 21 • Eight additional projects for generation cyber security, laptop and capital
22 business tool purchases for Generation Engineering, Electric Supply,
23 Environmental Services, Lab Services, Business Services, and Enterprise
24 Project Management (\$996,250).

25 **COMPANY-OWNED SOLAR RESOURCES**

26 **Q. Please explain the Company's projected capital expenditures for the 14-month**
27 **projected bridge period ending February 28, 2025 and the projected test year ending**
28 **February 28, 2026 for Company-owned solar resources.**

29 A. The Company plans to invest \$249.572 million in the 14-month projected bridge period
30 and \$275.959 million in the projected test year in Company-owned solar resources, as

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1 shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 50, columns (h) and (j),
2 respectively.

3 **Q. What is the basis for the projected \$249.572 million capital investment in the**
4 **14-month projected bridge period?**

5 A. The projected \$249.572 million capital investment in the 14-month projected bridge period
6 will fund the IRP-approved solar generation development. This entire investment amount
7 is reflected in two separate projects, Muskegon Solar and Spring Creek, which are each
8 greater than \$1 million and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2,
9 page 8, lines 32 and 33. The basis for these projects is described in the direct testimony of
10 Company witness Clark.

11 **Q. What is the basis for the projected \$275.959 million capital investment in the**
12 **projected test year?**

13 A. The projected \$275.959 million capital investment in the projected test year will fund the
14 IRP-approved solar generation development. This entire investment amount is reflected in
15 three separate projects, Muskegon Solar, Washtenaw, and Spring Creek, which are each
16 greater than \$1 million and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2,
17 page 9, lines 39 through 41. The basis for those projects is described in the direct testimony
18 of Company witness Clark.

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BATTERY ENERGY STORAGE SYSTEMS

Q. Please explain the Company's projected capital expenditures for the 14-month projected bridge period ending February 28, 2025 and the projected test year ending February 28, 2026 for BESS.

A. The Company plans to invest \$39.672 million in the 14-month projected bridge period and \$78.921 million in the projected test year in Company-owned battery resources, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 3, line 85, columns (h) and (j), respectively.

Q. What is the basis for the projected \$39.672 million capital investment in the 14-month projected bridge period?

A. The projected \$39.672 million capital investment in the 14-month projected bridge period will fund BESS. This entire investment amount is reflected in three separate projects, Armstrong, Iosco, and Weadock, which are each greater than \$1 million and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 34 through 36. The basis for these projects is described in the direct testimony of Company witness Clark.

Q. What is the basis for the projected \$78.921 million capital investment in the projected test year?

A. The projected \$78.921 million capital investment in the projected test year will fund the BESS. This entire investment amount is reflected in three separate projects, Armstrong, Iosco, and Weadock, which are each greater than \$1 million and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 42 through 44. The basis for those projects is described in the direct testimony of Company witness Clark.

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1 **Q. Are you supporting any other projected capital expenditures for generation related**
2 **projects in the test year ending February 28, 2026?**

3 A. Yes. I am also supporting an IT project, Generation Operations Digital Work Management.
4 The test year projected capital expenditure amount is \$713,873, and the test year projected
5 O&M expense amount is \$54,383. These amounts are reflected in the exhibits of Company
6 witness Shivaji Kandan. The scope of the project includes: the initial roll out for Electric
7 Generation at Ludington, and Renewable Generation, which would include: (1) purchase
8 of mobile field devices for Ludington, (2) purchase of additional mobile work management
9 software licenses, (3) development and configuration of forms and workflow for these
10 groups, and (4) enhancement of the wireless connection at Ludington.

11 **Q. What are the benefits of this technology project?**

12 A. This project provides the following value to the Company: (1) Productivity is improved,
13 and human struggle reduced by simplification of work tracking through the mobile
14 software. Time sheet charging is incorporated to the work order when someone on the
15 crew pushes the clock to start versus being separately entered through SAP Employee Self
16 Service. If there is more than one person on a crew, information is entered for the full crew
17 versus individually, including time tracking. Functionality is available to more easily
18 create a digital punch list in the field when a worker sees something instead of later writing
19 it on a punchboard and entering it separately into SAP; (2) Employee Engagement
20 improves as the more tech savvy candidate pool for these positions are looking for mobile
21 software to help them do their jobs; (3) Quality is improved by creating a digital punch list
22 when the technicians find an issue versus manually documenting it later. Accuracy
23 increases and rework decreases when updates are performed right at the time and place of

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1 the work instead of afterwards. Productivity can also be tracked and measured for further
2 improvements. This level of tracking is not possible with the current process and
3 information; (4) Safety is improved as employees have remote access to manuals to
4 reference before moving forward with and during their work. The access to manuals
5 increases productivity and better supports error reduction training by having the manuals
6 available so a worker can move beyond “I think” and “I believe.” The project will mitigate
7 the risk of work and safety errors from using outdated procedures; (5) For Renewable
8 Generation, the improved maintenance program will reduce equipment downtime resulting
9 in an increase to Megawatt hours produced; and (6) For Ludington, the new mobile devices
10 will allow working with electronic Systems Operations Management System (“eSOMS”)
11 which will improve productivity and reduce non-premise time.

12 **Q. Did the Company consider alternatives for this project?**

13 A. Yes. The alternatives considered include: (1) Utilizing an SAP work management mobile
14 solution. An SAP work management solution is not preferred since it is a new solution and
15 requires additional project and support cost; (2) Continuing the manual paper-based
16 process. Continuing the manual paper-based process was not chosen because of process
17 waste, re-work, and human error; (3) Customizing the existing electronic eSOMS mobile
18 application to add work management functions. A custom eSOMS mobile application was
19 not chosen because it would require additional project cost and an ongoing support budget
20 for a custom solution that the eSOMS product was not intended to support; and (4) Utilizing
21 an out-of-the-box solution to minimize cost and risk to the Company and its employees.
22 The combined Service Suite and digital form solution is the preferred option because it is

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1 a proven solution and provides the mobility and digital benefits at a lower cost than other
2 alternatives.

3 **GENERATION CAPITAL EXPENDITURES—SUMMARY**

4 **Q. Are the Company's capital expenditures in power generation reasonable and**
5 **prudent?**

6 A. Yes. As discussed, the proposed capital expenditures are directly aligned with the
7 Company's generation asset strategy and, as a result, will provide economic value for
8 power supply customers in the energy and resource adequacy markets. Other capital
9 expenditures in generation are related to regulatory and environmental compliance, and
10 thus are not discretionary. Company witnesses Clark and Monroe provide additional
11 discussion in their direct testimony.

12 **SECTION IV**

13 **GENERATION O&M EXPENSE**

14 **Q. What are the major drivers in determining the O&M expense levels you are**
15 **sponsoring in this proceeding?**

16 A. The major drivers are identifying the funding needed to support the daily operation and
17 maintenance of the Company's fleet of generating facilities and identifying the funding
18 needed for certain internal organizations that support Generation Operations.

19 **Q. For purposes of your direct testimony in this case, what does the Generation O&M**
20 **cost represent?**

21 A. In addition to the Company's generation fleet, I am sponsoring the O&M expenses for the
22 Electric Supply Operations and PSCR organization, Electric Regulation and Strategy
23 Implementation organization, Financial Planning organization, Renewable Energy

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Department, Contracts and Settlements organization, Generation Asset Management organization, Electric Sourcing and Resource Planning organization, and Enterprise Project Management and Environmental Services organization.

Q. Please describe Exhibit A-43 (RTB-4), page 1, Generation Operation and Maintenance Expenses.

A. Exhibit A-43 (RTB-4), page 1, identifies the actual 2023 through 12 Months Ending February 28, 2026 projected Generation O&M expenses. Specifically:

- Column (a) identifies each O&M expense category;
- Column (b) identifies the Actual 2023 Generation O&M expense as \$118,848,652;
- Column (c) identifies the 14-Month Projected Bridge Period Generation O&M expense as \$165,164,491; and
- Column (d) identifies the Projected Test Year Generation O&M expense as \$111,850,689.

HISTORICAL O&M EXPENSE

Q. How does Consumers Energy determine the level of Generation O&M spending?

A. Consumers Energy tracks the history and projects future maintenance needs of each generating unit. Personnel at the plants provide information on maintenance for each site or specific units. Once costs to operate and comply with regulations are prioritized, the Asset Strategy and Generation Planning organizations evaluate the plans required to maintain and/or improve the condition of the plant – weighing the estimated benefit to the customer for each project. Using this combination of information, a preliminary plan is prepared and reviewed to ensure high-priority issues are addressed and adequate resources and funding are available. After all appropriate levels of management have reviewed and

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1 approved the maintenance plan, a schedule is created. The overall objective is the safe,
2 reliable, and cost-effective generation of electricity.

3 **Q. How are Generation O&M expenses categorized?**

4 A. Generation O&M expenses are categorized into four primary components – “Base,”
5 “Environmental Operations,” “Major Maintenance,” and “Retention and Separation.”

6 **Q. What are Base O&M expenses?**

7 A. Base O&M expenses are comprised of two categories – labor and non-labor. Labor is the
8 primary component and typically has a predictable, stable rate of increase. Because most
9 of the Company’s generating units have been in service for years, the Company has an
10 excellent basis upon which to make accurate forecasts. Non-labor expenses also tend to
11 increase at a predictable rate and include items required to operate the plants. These items
12 include but are not limited to: (1) fuel (diesel and gasoline) for equipment and vehicles;
13 (2) material; (3) tools; (4) cleaning supplies; (5) facilities; (6) security; and (7) road and
14 grounds maintenance.

15 **Q. Please explain how the 2023 Actual O&M expenses were developed.**

16 A. The 2023 Actual O&M expenses were taken from Consumers Energy’s internal accounting
17 records.

18 **Q. Please explain how the 14-month projected bridge period and projected test year Base**
19 **O&M expenses were determined.**

20 A. Base O&M expenses for the projected bridge period ending February 28, 2025, and
21 projected test year ending February 28, 2026 shown on Exhibit A-43 (RTB-4), page 1,
22 line 1, columns (c) and (d), were determined by considering staffing levels and historical
23 spending. Total O&M expense for the years 2023 through the projected test year

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1 demonstrates average annual decreases of approximately 2.7%. As discussed later in this
2 direct testimony, this average annual decrease reflects a change in the mix of the
3 Company's owned generating assets as well as focused cost reductions. Exhibit A-43
4 (RTB-4), page 1, lines 3 and 4, identify Adjusted O&M expenses which are new or
5 projected to change from past years' expense levels. These include items that are required
6 by law to maintain environmental compliance, for the safety of employees, and to support
7 the reliability of service to customers, specifically, Environmental Operations and Major
8 Maintenance. Exhibit A-43 (RTB-4), page 1, line 5, identifies Adjusted O&M expenses
9 which are related to Retention and Separation expenses associated with the Karn and
10 Campbell sites. These expenses were required for the safe and reliable operation of Karn
11 Units 1 and 2 through their May 2023 retirement and are required for the continued safe
12 and reliable operation of Campbell Units 1, 2, and 3 through their May 2025 retirement.

13 **Q. How do the historical and projected test year O&M expense amounts compare to**
14 **prior years?**

15 A. The 2023 historical O&M expense amount of \$118.849 million and the projected test year
16 O&M expense amount of \$111.851 million compare quite favorably to the actual O&M
17 expense amounts for 2021 and 2022. The 2021 generation O&M expense amount was
18 \$155.204 million, and the 2022 generation O&M expense amount was \$150.031 million.
19 As I previously stated, the O&M expense reductions reflect a mix of generation asset
20 changes as well as other focused cost reductions.

21 **Q. Please explain Exhibit A-43 (RTB-4), page 2.**

22 A. Exhibit A-43 (RTB-4), page 2, presents the amounts of the projected O&M expenses that
23 were developed by applying either an inflation rate or contract rate to historical O&M

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1 expense. Column (b) presents the historical O&M expense. Column (c) presents the
2 amount of the historical O&M amount to which an inflation rate or contract rate applies.
3 Columns (e) and (g) present the amounts to which an inflation rate or contract rate were
4 applied for each period, respectively. Columns (d), (f), and (h) present contract and
5 inflation increases for each respective period. Amounts that were projected using other
6 methods are included in column (i). Column (j) is the projected test year O&M and is the
7 sum of columns (b), (d), (f), (h), and (i).

8 **Q. Please explain how the various inflation and contract rates were applied to Labor,**
9 **Material, Contractor, and Non-Labor Other O&M expense on Exhibit A-43 (RTB-4),**
10 **page 2.**

11 A. The historical labor on line 1, column (b) reflects a combination of both Operating
12 Maintenance and Construction ("OM&C") and non-represented labor. Inflation rates of
13 2.4%, 2.2%, and 2.2% were applied to labor on line 1, material on line 2, contractor on
14 line 3, and non-labor other on line 4 to develop the annual increase amounts in columns (d),
15 (f), and (h).

16 **Q. Please discuss how the adjustments on Exhibit A-43 (RTB-4), page 2, column (i) were**
17 **determined.**

18 A. As previously discussed, the Company projects the future maintenance needs of each unit.
19 The test period projected O&M expense amount of \$111.851 million reflects that
20 evaluation. Within the test period projected amount of \$111.851 million, there are several
21 adjustments that result in a projected amount that differs from the amount that is calculated
22 based solely on inflation.

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1 **Q. Please discuss the adjustments that are reflected in the test year projected amount of**
2 **\$111.851 million.**

3 A. As previously discussed, the Settlement Agreement reached in the Company's 2018 IRP
4 reflects the retirement of Karn Units 1 and 2 on May 31, 2023 and the Settlement
5 Agreement reached in the 2021 IRP reflects the retirement of Campbell Units 1, 2, and 3
6 on May 31, 2025 and the addition of Covert Units 1, 2 and 3 on June 1, 2023.

7 **Q. Please discuss the decrease in O&M expense for Karn Units 1 and 2.**

8 A. The 2023 O&M expense for Karn reflects the fact that Karn Units 1 and 2 retired on
9 May 31, 2023, leaving only Karn Units 3 and 4 operational. The actual O&M expense for
10 the Karn site in 2023 was \$19.091 million versus the projected O&M for the test year at
11 \$13.106 million, with the biggest decrease reflected in base O&M. The 2023 environmental
12 operations expense for the Karn site was \$2.254 million and that has been reduced to
13 \$0.093 million in the projected test year. The 2023 base O&M expense was \$16.554
14 million whereas the projected test year base O&M drops to \$10.411 million. The Karn
15 major maintenance expense increases from \$0.283 million in 2023 to \$2.602 million in the
16 projected test year. This increase reflects the fact that the Company limited the amount of
17 major maintenance it planned for Karn Units 3 and 4 in 2023 since its 2021 IRP proposed
18 the coincident retirement of those units with Karn Units 1 and 2. When the 2021 IRP
19 settlement did not include Karn Units 3 and 4 retiring early, the Company needed to
20 perform the deferred major maintenance. A complete discussion of the test year major
21 maintenance for Karn Units 3 and 4 is described later in this direct testimony.

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1 **Q. Please discuss the decrease in O&M expense for Campbell Units 1, 2 and 3.**

2 A. The projected test year O&M expense for Campbell reflects the fact that the Campbell units
3 will only operate for three months, March through May 2025. The projected test year
4 expense for Campbell is \$13.935 million, a \$29.392 million reduction from the actual 2023
5 O&M expense of \$43.327 million. The biggest reduction from the historical year to the
6 projected test year is reflected in base O&M expense. The base O&M expense in the
7 projected test year is \$11.204 million, a \$23.653 million reduction from the historical
8 expense of \$34.858 million. The 2023 environmental operations expense for Campbell
9 was \$6.421 million and that has been reduced to \$2.186 million in the projected test year.
10 The Campbell major maintenance expense decreases from \$2.049 million in 2023 to only
11 \$0.545 million in the projected test year. A complete discussion of the test year major
12 maintenance for Karn Units 3 and 4 is described later in this direct testimony.

13 **Q. Please discuss the increase in O&M expense for Covert Units 1, 2, and 3.**

14 A. The 2023 O&M expense for Covert reflects the fact that the Company didn't take
15 ownership of the plant until June 1, 2023. The actual O&M expense for Covert Units 1, 2
16 and 3 in 2023 was \$7.413 million for the period from June 1, 2023 through December 31,
17 2023. The projected O&M for the test year is \$16.873 million, with the biggest increase
18 reflected in major maintenance. The 2023 expense for major maintenance was
19 \$2.144 million however it is project to total \$7.706 million in the test year. A complete
20 discussion of the test year major maintenance for Covert is described later in this direct
21 testimony. The 2023 environmental operations expense for Covert was \$0.072 million and
22 that expense is slightly lower at \$0.053 million in the projected test year. The base O&M

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1 reflects an increase from \$5.196 million for the period from June 1, 2023 through
2 December 31, 2023, to \$9.114 million in the test year.

3 **Q. Are these generation asset changes the only reasons for the reduced O&M expense?**

4 A. No. As I previously indicated, the Company has implemented other focused cost
5 reductions that have directly impacted both the actual 2023 O&M expense and the
6 projected test year expense. These cost reductions are primarily represented by headcount
7 reductions during 2023 which have reduced both capital expenditures and O&M expense.

8 **Q. Did the Company implement any projects that exclusively impacted capital**
9 **expenditures?**

10 A. Yes. The Company has implemented an improved governance process and key
11 performance management metrics that will allow it to improve the efficiency of its capital
12 expenditures. While the Company will not necessarily reduce its overall capital
13 expenditures, it does expect that it will be able to accomplish more work with the same
14 amount of capital.

15 **Q. Did the Company implement any generation capital projects which reduce other**
16 **customer costs?**

17 A. Yes. The Company implemented a project at Jackson for the HRSG Burner Element
18 Isolation Valves Addition (see Exhibit A-12 (RTB-3), Schedule B-5.2, page 7, line 9) in
19 2023 that will reduce both O&M and PSCR expense. The project involved the addition of
20 automated low point drain and vent on each gas manifold, the addition of isolation valves
21 on all burner elements, and burner management system ("BMS") logic changes to control
22 drains and vents. The benefits of the project are the mitigation of condensation in burner
23 piping and elements which leads to ignition failure, burner tube failure, and flame

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1 impingement which would eventually lead to burner elements replacements because of
2 those issues. In addition, the project will increase generation production or capability due
3 to less duct burner down time because of the ability to isolate individual duct burners rather
4 than an entire HRSG. The increased generation production or capability is intended to
5 result in a reduction of PSCR costs, and the improved reliability of the burner elements
6 will result in reduced O&M expense.

7 **ENVIRONMENTAL OPERATIONS**

8 **Q. What are Environmental Operations expenses?**

9 A. Environmental Operations expenses consist of labor and materials supporting the
10 operations of the Company's AQCS. As Federal and State emissions standards require
11 cleaner air, Consumers Energy has installed AQCS to comply with these regulations.
12 Consumers Energy deployed its full suite of AQCS devices in 2016, with 2017 being the
13 first calendar year of operation. Now that the Company has experienced multiple calendar
14 years of operation, the Company anticipates these expenses to remain relatively consistent
15 going forward. However, because the cost to operate and maintain these critical pieces of
16 equipment is directly related to the operation of the coal-fired power plants they support,
17 yearly variances in the total Environmental Operations expense should be expected based
18 on the operation of the coal plants in a given year.

19 **Q. Please explain how the projected Environmental Operations expenses for the**
20 **projected bridge period ending February 28, 2025 and test year ending February 28,**
21 **2026 were calculated.**

22 A. Environmental Operations expenses are a combination of O&M costs related to the
23 environmental equipment at the Karn and Campbell sites. The operations component is

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1 primarily calculated using labor costs for operations and environmental waste disposal.
2 The maintenance component is based on a combination of historical and estimated planned
3 maintenance costs on the specific components of environmental equipment. 2023 was the
4 seventh full year of operations of the environmental equipment at both Campbell and Karn,
5 and the Company now has robust historical data to use in projecting these expenses.
6 However, as reflected on Exhibit A-43 (RTB-4), page 1, line 3, columns (b) and (d), the
7 walk from the 2023 historical expense of \$9.225 million to the projected test year expense
8 of \$2.584 million reflects a cost reduction of \$6.641 million despite inflationary increases.
9 This cost reduction is a direct reflection of the retirement of Karn Units 1 and 2 on May 31,
10 2023 and the retirement of Campbell Units 1, 2 and 3 on May 31, 2025.

11 **MAJOR MAINTENANCE**

12 **Q. What are Major Maintenance expenses?**

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

19 **Q. Please explain how the Major Maintenance O&M expenses for the projected bridge**
20 **period ending February 28, 2025 and test year ending February 28, 2026 were**
21 **determined.**

22 A. Major Maintenance expenses are determined by tracking both the historical and future
23 maintenance needs for each site and unit, considering operation safety, unit reliability, and

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1 maximum customer value. Individual projects are calculated in a manner similar to capital
2 projects, as discussed earlier in this direct testimony.

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

4 A. The Company projects that it will incur \$31.203 million in Major Maintenance O&M
5 expenses during the test year, as identified by Exhibit A-43 (RTB-4), page 1, line 4,
6 column (d). Test year Major Maintenance expense by generating unit is presented on
7 Exhibit A-43 (RTB-4), page 3, column (d).

8 **Q. Why is Consumers Energy spending \$31.203 million in Total Major Maintenance**
9 **O&M expense during the projected test year ending February 28, 2026?**

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

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

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

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1 prices, unit performance, and simple timing variations can impact the cost and scheduling
2 of Major Maintenance.

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

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

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

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

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

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

22 **Q. What are the categories of Major Maintenance?**

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

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

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

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

18 A. Boiler inspections assess the fire (outside) and steam (inside) sides of boiler tubing for
19 weaknesses that will ultimately result in water/steam leaks. After the boiler has been
20 properly opened, ventilated, and cleaned, scaffolding is constructed inside the boiler to
21 provide access to the boiler tubes. Inspections are completed using a number of different
22 methods – visual, non-destructive, and destructive. Visual and non-destructive testing are
23 the most common methods of inspection. Non-destructive testing incorporates the use of

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1 ultrasonic, x-ray, magnetic particle, or like technologies to measure pipe wall thickness.
2 Boiler tubes that are in poor condition or exceed minimum wall thickness are repaired or
3 replaced. After all repairs are complete, boiler tubes are pressure tested. Each boiler is
4 inspected on a specific time schedule, with a one-, two-, or three-year maximum interval.
5 Internal components with known problems are inspected more frequently. External
6 inspections are performed daily by Generation Operations and annually by state inspectors.

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

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

14 **Q. Please define non-outage maintenance.**

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

18 **Campbell Units 1 and 2 Major Maintenance**

19 **Q. Please describe Campbell Units 1 and 2 Major Maintenance expenses for the**
20 **projected test year ending February 28, 2026.**

21 A. As shown on Exhibit A-43 (RTB-4), page 3, line 1, column (d), Campbell Units 1 and 2
22 Major Maintenance expense is forecasted to be \$0.268 million in the projected test year
23 ending February 28, 2026, and includes:

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- Campbell Units 1 and 2 Periodic Outage Major Maintenance (\$60,000). The scope of this project is to perform boiler maintenance activities during outages during the projected test year. Expenses include planning, engineering services, materials, and overtime labor;
- Campbell Unit 1 Pulverizer Maintenance (\$60,000). The scope of this project is the procurement of required parts to support the on-going maintenance of the coal pulverizers to maintain their operability. This maintenance work will allow the Company to keep the minimum number of mills in service and, as a result, avoid unit derates due to degraded conditions. The performance of this work will result in safe, reliable, and efficient unit operation;
- Campbell Unit 2 Mill Maintenance — Parts Only Boiler Plant Equipment (\$60,000). The scope of this project is the procurement of required parts to support the on-going maintenance on the coal mill/pulverizers to maintain their operability. This maintenance work will allow the Company to keep the minimum number of mills in service and, as a result, avoid unit derates due to degraded conditions. The performance of this work will result in safe, reliable, and efficient unit operation; and
- One project common to Campbell Units 1 and 2 totaling \$30,010 and two Site Common Major Maintenance projects totaling \$135,577 which are shared with Campbell Unit 3. Campbell Units 1 and 2 receive a 43% allocation totaling \$58,298 and Campbell Unit 3 receives a 57% allocation or \$77,279. These projects, all of which represent \$92,377 or less in expense, include fuel handling dumper outage repairs, deepwater intake screen inspection, and SDA O&M costs.

Campbell Unit 3 Major Maintenance

Q. Please describe Campbell Unit 3 Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 2, column (d), Campbell Unit 3 Major Maintenance expense is forecasted to be \$0.277 million in the test year and includes:

- Campbell Unit 3 Pulverizer Maintenance — Parts Only Mills-Boiler Plant Equipment (\$60,000). The scope of this project is the procurement of required parts to support the on-going maintenance on the coal pulverizers to maintain their operability. This maintenance work will allow the Company to keep the minimum number of mills in service and, as a result, avoid unit derates due to degraded conditions. The performance of this work will result in safe, reliable, and efficient unit operation;

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- Campbell Unit 3 Periodic Outage Major Maintenance (\$94,384). The scope of this project is to perform boiler, turbine, and BOP maintenance activities during outages during the project test year. Expenses include planning, engineering services, materials, and overtime labor. Performance of this work will result in improved unit reliability and performance; and
- One other Campbell Unit 3 project totaling \$45,000 and two Site Commons projects that I discussed previously with the Campbell Unit 3 allocation totaling \$77,279.

Karn Units 1 and 2 Major Maintenance

Q. Please describe Karn Units 1 and 2 Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 3, column (d), Karn Units 1 and 2 Major Maintenance expense is forecasted to be \$0.100 million in the projected test year ending February 28, 2026. This forecasted expense for the projected test year ending February 28, 2026 is for vegetation removal.

Covert Plant Major Maintenance

Q. Please describe the Covert Plant Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 8, column (d), the Covert Plant Major Maintenance expense is forecasted to be \$7.706 million in the projected test year ending February 28, 2026, and includes:

- Covert Plant LTSA Major Maintenance (\$2,611,312). This is the major maintenance portion of the Mitsubishi negotiated services that cover the planned normal maintenance of each generating unit. The projected major maintenance expenses are based upon variable fees paid to Mitsubishi for maintenance services which are based on an effective fired hours basis pursuant to the LTSA. Unlike the GE LTSAs for the Jackson and Zeeland plants, there are no milestone payments associated with the fee structure for the Mitsubishi LTSA. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected pre-mature failures of the equipment. This will help maximize availability and,

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as a result, optimize customer value for the site. Normal maintenance will ensure the Company continues reliable operation of the units;

- Covert Plant LTSA extra work Major Maintenance (\$1,492,500). This is the major maintenance portion of the Mitsubishi negotiated services that are not covered in the planned normal maintenance of each generating unit. Based on historical outage experience, there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items not covered under the LTSA that need to be addressed are labor and material to replace the following: blading, ammonia delivery system, SCR catalyst, turbine rotors, cooling towers, and turbine cooling air cooler;
- Covert Plant Capacity Factor Used For Water and Chemicals (\$1,216,667). This item provides for the city water used by the Covert Plant, and for the chemicals required to operate the water purification systems that are used to purify the makeup water prior to use;
- Reverse Osmosis System (“RO”), operation agreement (\$461,667). The scope of this project is to contract with a third party to operate and maintain the RO system;
- Covert Plant Base Outage Funding – Boiler plant equipment (\$483,333). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages;
- Covert Plant HEPS/FAC/DAST Inspections (\$913,333). This project will include the performance of regulatory required high energy piping surveillance (“HEPS”), deaerator and its storage tank (“DAST”) mid cycle inspection, and flow accelerated corrosion (“FAC”) inspection; and
- Four additional projects for Covert totaling \$527,500 in expenses, with each individual project representing \$275,000 or less in expenses. These projects include NERC relay and DC testing, ITC switchyard upgrades, gas turbine exhaust expansion joints repairs, and 345 kV transformer bushing power factor testing.

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Karn Units 3 and 4 Major Maintenance

Q. Please describe Karn Units 3 and 4 Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 4, column (d), Karn Units 3 and 4 Major Maintenance expense is forecasted to be \$2.502 million in the projected test year ending February 28, 2026, and includes:

- Karn Units 3 and 4 Periodic Outage Major Maintenance (\$355,833). The scope of this project is to perform boiler maintenance activities during scheduled periodic outages during the projected test year. Expenses include planning, engineering services, materials, and overtime labor;
- Karn Units 3 and 4 HEPS/FAC/DAST Inspections (\$375,000 per unit). This project will include the performance of regulatory required inspections;
- Karn Unit 3 Turbine Valve Inspections (\$241,667). The scope of this project is to perform the Karn Unit 3 turbine valve inspections;
- Karn Unit 4 Main Transformer Bladder Replacement (\$208,333). The scope of this project is to replace the bladder. The main transformer conservator bladder is broken and open to atmosphere, making the oil susceptible to air bubbles and increasing the risk of transformer failure; and
- Fourteen additional projects for Karn Units 3 and 4 totaling \$946,333 in expenses, with each individual project representing \$150,000 or less in expenses. These projects include critical motor major maintenance, forced draft and induced draft fan alignments, station power relay maintenance, and opacity critical equipment repairs.

Zeeland Plant Major Maintenance

Q. Please describe Zeeland Plant Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 6, column (d), Zeeland Plant Major Maintenance expense is forecasted to be \$5.232 million in the projected test year ending February 28, 2026, and includes:

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- Zeeland Plant LTSA — Running Maintenance Contract (\$2,048,614). Consumers Energy has a long-term maintenance agreement with GE to perform the major maintenance and capital repairs necessary to maintain unit reliability. This item represents the O&M component of that service agreement;
- Zeeland Plant Capacity Factor Used for Water and Chemicals (\$1,255,417). This item provides for the city water used by the Zeeland Plant, and for the chemicals required to operate the water purification systems that are used to purify the makeup water prior to use;
- Base Outage — Boiler Plant Equipment (\$558,333). During planned and scheduled periodic outages, inspections and repairs are performed. Base boiler maintenance and outage is needed to complete condition assessment inspections of the boiler and major components, complete repairs on valves and large plant equipment, and complete repairs that are identified during shutdowns and condition assessments;
- Zeeland Site Commons Deep Well Injection Cleaning (\$323,333). The scope of this project is the third-party cleaning of the well. Cleaning the well allows Zeeland to continue to operate in the most economical means practical and maintain the required plant equipment. Failure to clean the well would require the plant to blowdown all cooling tower concentrate to the city sewer at a considerable expense. This activity is performed on a triennial basis; and
- Fourteen additional projects totaling \$1,045,984 in expenses, with each individual project representing \$208,333 or less in expenses. These include excitation and isolation transformer testing and maintenance, HEPS, FAC inspection, large oil-filled transformer maintenance, breaker maintenance, and NERC-required relay testing.

Jackson Plant Major Maintenance

Q. Please describe Jackson Plant Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 7, column (d), Jackson Plant Major Maintenance expense is forecasted to be \$3.852 million in the projected test year ending February 28, 2026. This forecasted expense consists of:

- Jackson Plant Capacity Factor Used for Water and Chemicals (\$1,900,000). This item provides for the city water used by the Jackson Plant, and for the chemicals required to operate the water purification systems that are used to purify the makeup water prior to use. The projected expense is based upon

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historical monthly invoice values as well as consideration of the capital project previously discussed in this testimony for site generating water;

- Jackson Plant Non-LTSA Turbine and jet engine repairs (\$391,667). The scope of this major maintenance is to perform jet engine repairs including bushing replacements every 12,000 hours;
- Jackson Plant LTSA — Running Maintenance Contract (\$508,333). Consumers Energy has a long-term maintenance agreement with GE to perform the major maintenance and capital repairs necessary to maintain unit reliability. This item represents the O&M component of that service agreement;
- Jackson Plant Base Outage - Boiler plant equipment (\$250,000). During planned and scheduled periodic outages, inspections and repairs are performed. Base boiler maintenance and outage is needed to complete condition assessment inspections of the boiler and major components, complete repairs on valves and large plant equipment, and complete repairs that are identified during shutdowns and condition assessments; and
- Ten additional projects totaling \$801,565 with each individual project representing \$241,853 or less in expenses. These include HEPS, FAC, pre-Filter replacement, high voltage maintenance and NERC testing, and filter house roof maintenance.

LPS Major Maintenance

Q. Please describe LPS Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 9, column (d), LPS Major Maintenance expense is forecasted to be \$4.445 million in the projected test year ending February 28, 2026, including:

- Fish Barrier Net - Installation, cleaning, and repairs and removal (\$2,140,000). This is a FERC regulatory requirement. The net is installed annually and maintained to meet FERC license requirements (and the requirements of a Settlement Agreement with federal and state natural resource agencies) and minimizes the impact of LPS on fish in Lake Michigan;
- Nine Year Unit Mechanical Interval Inspection and Replacement (\$570,000). The scope of this project is to perform replacement of common wear elements and consumable items associated with the pump/turbine units. This work will

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include the first nine-year maintenance interval for each of the six units as well as up front planning and procurement funding in the first year;

- Reservoir remediation (\$535,833). This is FERC required and related to dam safety to ensure the Company maintains the integrity of the Ludington pond; and
- Twenty-two additional projects totaling \$1,199,508, with each individual project representing less than \$161,000 in expenses. These include asphalt liner inspection repairs, penstock condition assessment and monitoring study, Depression Air Compressor Maintenance, periodic outage inspections and non-destructive examination, lube oil room repair, Polychlorinated Biphenyl removal and disposal, and powerhouse slope terrace drain cleanout.

Hydro Major Maintenance

Q. Please describe Hydro Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 10, column (d), Hydro Major Maintenance expense is forecasted to be \$5.776 million in the projected test year ending February 28, 2026, and includes:

- Hydro License Initiatives (\$2,158,667). A FERC requirement, this item resulted from the relicensing of Au Sable, Manistee, and Muskegon River dams, with the main result being that the Company has annual license commitments. License commitments include some recreation, fish payments, and water quality such as upwelling systems licenses;
- Hydro annual FERC Dam Safety Requirements including Part 12 Inspections (\$1,446,475). The scope of this project is to perform the FERC-required dam safety inspections on an annual basis, and the FERC-required Part 12 inspections on each dam every five years (FERC Part 12 regulations are discussed in Mr. Monroe's direct testimony). A similar level of expense is budgeted annually from 2025 through 2028;
- Hardy Intake Tower Brick Repair (\$241,667). The scope of this project is to replace all the deteriorated interior brick inside the intake tower for the full height. The Hardy intake tower brickwork has been slowly deteriorating for the last few years. The bricks are crumbling to the touch and has areas with significant delamination throughout the entire height of the walls (34ft). If the deterioration becomes significant enough, it may impact the headgate hoists and the head gates installation safety of the Operations staff;

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- Tippy Spillway Chamber Inspections and Repairs (\$202,500). The project scope includes performing spillway chamber inspections, engineering for spillway chamber repairs and construction of repairs. The Tippy spillway chambers are hollow chambers underneath the spillway. In the spillway chambers, the concrete is deteriorated, rebar is exposed, and there is seepage present;
- Hydro Concrete Repairs (\$206,958). The scope of this project is to make necessary repairs to deteriorating concrete at all 13 River Hydro facilities. This budgeted amount will allow for the performance of necessary repairs which are identified after spring flows or general deterioration. The identification of large concrete repairs will be considered in the annual budgeting process; and
- Twenty-six additional projects totaling \$1,520,083 with each individual project representing \$150,000 or less in expenses. These projects include Cooke Powerhouse Divider Pier, Foote Auxiliary Spillway Pilot Channel and Embankment Crest Grading Project, Tippy Log Chute Repairs, base outage funding, headgate evaluation and repairs, relief well piezometer cleaning, and condition/risk assessments.

Solar Major Maintenance

Q. Please describe Solar Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 11, column (d), Solar Major Maintenance expense is forecasted to be \$0.677 million in the projected test year ending February 28, 2026 and includes three projects, all to provide IT support for the Mustang Mile, Muskegon Solar, and Washtenaw Solar IRP solicitation projects. For each of the solar sites, the major maintenance funding includes plant setup in SAP, and payment of the OSISoft PI Historian and Bazefield SCADA overlay license fees.

Admin and Other Major Maintenance

Q. Please describe Admin and Other Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 12, column (d), Admin and Other Major Maintenance expense is forecasted to be \$0.150 million in the projected test year ending

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February 28, 2026 and includes one project: Generation control systems cyber maintenance software support. Specifically, this project provides funding for software maintenance contracts from multiple vendor systems that are not part of the DCS control vendor service contracts.

Classic 7 Major Maintenance

Q. Please describe Classic 7 (B.C. Cobb (“Cobb”), J.C. Weadock (“Weadock”), and J.R. Whiting (“Whiting”) units) Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 5, column (d), Classic 7 Major Maintenance expense is forecasted to be \$0.218 million in the projected test year ending February 28, 2026.

Q. Why is Consumers Energy projecting to spend \$0.218 million in Major Maintenance on the Classic 7 units in the projected test year ending February 28, 2026?

A. Although the Classic 7 units were retired in 2016, environmental regulations require the continued maintenance of the on-site ash ponds, which includes Cobb landfill and ash pond O&M, Weadock landfill license and inspections, and Whiting ash pond post-closure care.

**KARN AND CAMPBELL RETENTION AND SEPARATION PLAN
EXPENSE**

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

A. As reflected on Exhibit A-43 (RTB-4), page 1, line 5, the Company incurred actual expense of \$17.348 million in 2023, and is projecting expense of \$11.158 million in the 14-month projected bridge period, and \$4.621 million in the projected test year. The actual 2023 expense of \$17.348 million is based upon expense of \$1.501 million for Karn and

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1 \$15.847 million for Campbell. The 14-month projected bridge period expense of
2 \$11.158 million is entirely based upon expense of \$11.158 million for Campbell. The
3 projected test year expense of \$4.621 million is based upon expense of \$4.621 million for
4 Campbell.

5 **Q. Is the Company requesting O&M recovery of the \$4.621 million projected amount**
6 **for the projected test year?**

7 A. No. The Company is not requesting approval of this projected amount in Generation O&M
8 expense. The Company received approval in electric rate case, Case No. U-20697, to defer
9 the recovery of the Karn Retention and Separation O&M amounts for 2021 through 2023.
10 The Company received approval to defer the recovery of the Campbell retention and
11 separation amounts in the Settlement Agreement in its 2021 IRP. As such, the projected
12 amounts for 2023 through the projected test year ending February 28, 2026 are not included
13 in the Total O&M amounts on Exhibit A-43 (RTB-4), page 1, line 6, columns (b), (c) and
14 (d). Company witness Aponte supports regulatory asset treatment of these expenses in her
15 direct testimony.

16 **Q. Please describe the Karn retention and separation plan.**

17 A. The Karn retention and separation plan is a people strategy that the Company has
18 implemented to ensure that it could retain the necessary qualified employees to operate
19 Karn Units 1 and 2 through their retirement date in May 2023, as well as during the cold
20 and dark time period following retirement. The cold and dark condition refers to the period
21 following plant retirement and prior to plant decommissioning. During this period, limited
22 environmental remediation and perhaps partial demolition is performed. The facility may
23 be physically secured with fencing and other measures to prevent vandalism or theft so as

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1 to limit liability risks. On June 7, 2019, the MPSC approved the Company's 2018 IRP
2 Settlement Agreement, which included the retirement of Karn Units 1 and 2 in May 2023.
3 The Company's IRP included detailed support of the Company's need to implement a
4 retention and separation plan to ensure that it could operate the plants safely and reliably
5 through their retirement date.

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

7 A. The Company had a strong interest in keeping qualified employees working at Karn Units 1
8 and 2 through their retirement date to ensure safe and reliable operations. The retention
9 component will allow the Company to retain employees that may seek employment at other
10 Company locations or outside of the Company. The Company's ability to hire new
11 employees at Karn Units 1 and 2 became increasingly difficult given the short remaining
12 lifespan of the units and, to the extent that the Company had the ability to hire new
13 employees, the training time necessary for any new hires provided a significant challenge
14 to operating the units both safely and reliably. The retention component utilized the best
15 practices that the Company employed in retiring the Classic 7.

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

17 A. Now that Karn Units 1 and 2 are retired, the Company is following the terms of the
18 collective bargaining agreement for OM&C employees represented by the Utility Workers
19 Union of America ("UWUA"), and the terms of the employee handbook policy and
20 separation plan for non-represented exempt and non-exempt employees. The structure and
21 amount of the severance offers varies based on employee salary and classification due to
22 differences in the terms of the separation plan covering non-represented employees and the
23 bargaining agreement for UWUA-represented employees. In the event that exempt or

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1 non-exempt employees cannot find placement within the Company within 60 miles from
2 their current location, they will be offered involuntary severance in accordance with the
3 terms of the Company's Salaried Separation Plan. The Company's Working Agreement
4 with the UWUA governs separation for OM&C employees who elect to leave the Company
5 rather than accept a new position as well as relocation expenses if they accept a position
6 more than 60 miles away from their current location.

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

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

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

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

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

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1 Employees receive an annual incentive which graduated from 20% to 30% of their
2 base pay for service each November in years 2019, 2020, and 2021, for staying at Karn and
3 rendering service for the next 12 months. The employee had to stay at Karn until
4 October 31 of the following year to receive the payment; if the employee stayed until that
5 date, the incentive was paid out to the employee within 30 days. If the employee separated
6 from the Company before October 31 of the next year, the employee forfeited the annual
7 incentive. Eligible employees received their first annual incentive payment in November
8 2020, a second payment in November 2021, and a third payment in November 2022.

9 Employees received their final retention incentive equal to 60% of their base pay
10 following plant retirement if the employee was still at Karn. The payment was intended to
11 incentivize employees to stay until the plant goes cold and dark and compensate employees
12 for the service they rendered for the eight months (November 2022 through June 2023)
13 prior to the payment.

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

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

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

22 A. The Company is proud of the fact that following the retirement of the Classic 7 in 2016,
23 all Company employees that desired to continue employment with the Company were able

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1 to do so. However, the Company is also aware of the fact that it has fewer Company
2 locations (11 within 60 miles of the Karn site) to which employees can relocate, than it did
3 in 2016. As such, the Company anticipated the need to make severance payments to those
4 employees that cannot find placement. As I previously stated, the Company is following
5 the terms of the collective bargaining agreement for OM&C employees represented by the
6 UWUA, and the terms of the employee handbook policy and separation plan for
7 non-represented exempt and non-exempt employees.

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

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

20 **Q. Please describe the Campbell retention plan.**

21 A. The Campbell retention plan is a people strategy that the Company has proposed in its 2021
22 IRP. As previously discussed, the Company's 2021 IRP PCA reflects the retirement of
23 Campbell Units 1, 2, and 3 on May 31, 2025. This retention plan was proposed in order to

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1 retain employees through the closure of the three Campbell units. This strategy is
2 necessary to ensure that the Company can operate the Campbell units safely and reliably
3 through their retirement date. This incentive program is the same program that is currently
4 in place for employees at the Karn site.

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

6 A. For similar reasons described in the Karn retention plan, the Company has a strong interest
7 in keeping qualified employees working at the Campbell site through their retirement date
8 to ensure safe and reliable operations. The retention component will allow the Company
9 to retain employees that may seek employment at other Company locations or outside of
10 the Company. Similar to the situation at the Karn site, it will be increasingly difficult to
11 hire new employees at the Campbell site given the short remaining lifespan of the units
12 and, to the extent that the Company has the ability to hire new employees, the training time
13 necessary for any new hires will provide a significant challenge to operating the three units
14 both safely and reliably.

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

16 A. When the Campbell units are retired, the Company plans to follow the terms of the
17 collective bargaining agreement for OM&C employees represented by the UWUA, and the
18 terms of the employee handbook policy and separation plan for non-represented exempt
19 and non-exempt employees. The structure and amount of the severance offers will vary
20 based on employee salary and classification due to differences in the terms of the separation
21 plan covering non-represented employees and the bargaining agreement for
22 UWUA-represented employees. In the event that exempt or non-exempt employees cannot
23 find placement within the Company within 60 miles from their current location, they will

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1 be offered involuntary severance in accordance with the terms of the Company's Salaried
2 Separation Plan. The Company's Working Agreement with the UWUA governs separation
3 for OM&C employees who elect to leave the Company rather than accept a new position
4 as well as relocation expenses if they accept a position more than 60 miles away from their
5 current location.

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

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

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

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

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

22 Employees receive a periodic incentive which graduates from 20% to 30% of their
23 base pay for service each November in years 2022, 2023, and 2024, for staying at Campbell

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

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

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

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

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

20 A. The Company is proud of the fact that following the retirement of the Classic 7 in 2016,
21 all Company employees that desired to continue employment with the Company were able
22 to do so. However, the Company is also aware of the fact that it has fewer Company
23 locations (seven within 60 miles of the Campbell site) to which employees can relocate,

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1 than it did in 2016. In addition, the Company will also have retired at least two of the Karn
2 generating units in 2023, thereby further reducing the available positions. As such, the
3 Company has anticipated the need to make severance payments to those employees that
4 cannot find placement. As I previously stated, the Company plans to follow the terms of
5 the collective bargaining agreement for OM&C employees represented by the UWUA, and
6 the terms of the employee handbook policy and separation plan for non-represented exempt
7 and non-exempt employees, as previously discussed for the Karn retention and separation
8 plan.

9 **Q. Does this conclude your direct testimony?**

10 **A.** Yes, it does.

Attachment HH

DOE, Special Environmental Analysis (2006)

Special Environmental Analysis

**For Actions Taken under U.S. Department of Energy
Emergency Orders Regarding Operation of the
Potomac River Generating
Station in Alexandria, Virginia**



November 2006

U.S. Department of Energy
Washington, D.C.

COVER SHEET

Responsible Agency:

U.S. Department of Energy (DOE)

Cooperating Agency:

U.S. Environmental Protection Agency

Title:

Special Environmental Analysis for Actions Taken under DOE Emergency Orders Regarding Operation of the Potomac River Generating Station in Alexandria, Virginia

Location:

Alexandria, VA, and Washington, DC

Contacts:

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Abstract:

On December 20, 2005, the Secretary of Energy issued an emergency order, DOE Order 202-05-03, requiring Mirant's Potomac River Generating Station in Alexandria, Virginia, to operate under limited circumstances. On September 28, 2006, the Secretary extended the Order, including all of its terms and conditions, DOE Order 202-06-2, until December 1, 2006. This SEA includes descriptions of the DOE emergency orders; assessments of the direct, indirect, and cumulative impacts resulting from the emergency orders; and descriptions of alternative actions for potential future decision-making that include mitigation. This SEA covers a period of about 24 months beginning in December 2005.

Public Comment:

Simultaneously with issuance of this SEA, the Secretary is issuing another temporary extension of the emergency order, including all of its terms and conditions, DOE Order 202-07-1, until February 1, 2007. DOE is placing the document on DOE's internet websites (<http://www.oe.energy.gov/permitting/372.htm> and <http://www.eh.doe.gov/nepa/documents/pub.html>) and making it available at the public reading room at DOE headquarters. An announcement of the availability of the SEA is also being made in the *Federal Register*. Comments on this SEA are due on January 8, 2007, and will be considered in any future decision-making on this matter. Due to postal security procedures, comments sent through U.S. mail may be delayed, and DOE recommends that commentors use other means.

SUMMARY

On December 20, 2005, the Secretary of Energy issued an emergency order (“DOE Order” or “Order”) to Mirant Potomac River, LLC (Mirant) pursuant to Section 202(c) of the Federal Power Act (FPA). The Order directed Mirant to operate its Potomac River Generating Station (“the Plant”) in Alexandria, Virginia, in specific and limited circumstances in order to reduce the risk of a blackout in the Central Washington, D.C. area, while avoiding, to the extent possible, exceedances of the National Ambient Air Quality Standards (NAAQS) (text box). The Order was to expire on September 30, 2006, but DOE issued a temporary extension of the Order, until December 1, 2006, to allow for completion of this Special Environmental Analysis (SEA). This SEA assesses impacts resulting from the Orders and from potential future alternative actions DOE may take in this matter. DOE is accepting public comment on this SEA and will consider all comments submitted in any future decision-making.

In emergency situations, pursuant to 40 CFR 1506.11, the Council on Environmental Quality’s (CEQ) National Environmental Policy Act of 1969 (NEPA) regulations call for agencies to consult with CEQ to determine what alternative arrangements the agency will take in lieu of preparing an environmental impact statement (EIS) that might otherwise be required for the relevant action. DOE is issuing this SEA in compliance with the “alternative arrangements” plan agreed upon with CEQ.

National Ambient Air Quality Standards (NAAQS)

The Clean Air Act, which was last amended in 1990, requires the Environmental Protection Agency (EPA) to set NAAQS for pollutants considered harmful to public health and the environment. EPA has set NAAQS for seven “criteria” pollutants: sulfur dioxide (SO₂), nitrogen dioxide (NO₂), lead, carbon monoxide (CO), ozone, particulate matter less than or equal to 10 µm in aerodynamic diameter (PM₁₀), and particulate matter less than or equal to 2.5 µm in aerodynamic diameter (PM_{2.5}). Each NAAQS has a specific averaging time (e.g., 3-hour or 24-hour SO₂ standard) that represents the time period over which modeled air pollutant concentrations are analyzed for the purpose of determining attainment with the NAAQS. The NAAQS are implemented at the state level through State Implementation Plans (SIPs). SIPs use individual source emissions limitations to help attain and maintain the NAAQS.

Background

The Plant is a 482-MW electricity generating facility located on the Potomac River in Alexandria, Virginia, about five miles (8 km) from the U.S. Capitol building (Figure S-1). The Plant consists of five generating units, each with its own exhaust stack. Because the Plant is located three miles (5 km) from the Ronald Reagan Washington National Airport and is within the flight path of the airplanes that fly in and out of that airport, it has stacks that are shorter than

normal for similar facilities. The Plant uses oil to pre-heat each of its units and then burns coal, which it receives via rail car, to generate electricity. The generated electricity is transmitted to the central business district of Washington, D.C., many Federal institutions, the Georgetown area, as well as other portions of Northwest D.C. and the D.C. Water and Sewer Authority's Blue Plains Wastewater Treatment Plant (collectively called the "Central D.C. area").

The Plant site was relatively remote in 1949 when the Plant began operation. However, residential communities and commercial properties have grown up and around the Plant over the last 50 years, notably a condominium building, Marina Towers, built only 300 yards (270 m) from the Plant in the 1960s. Since 2001, residents of Marina Towers have complained about air quality impacts and associated health impacts of the Plant's operation. Since 2003, state and Federal environmental agencies have been working with Mirant to settle alleged violations of the Plant's operating permit limit for nitrogen oxide (NO_x) emissions. The alleged violations resulted in a judicial consent decree (EPA 2004) in September 2004 and an amended judicial consent decree in May 2006 (EPA 2006g). Part of the 2004 settlement required Mirant to perform a modeling analysis to predict the effect of "downwash"¹ from the Plant on ambient concentrations of several NAAQS pollutants. The study showed significant modeled exceedances of three NAAQS pollutants from downwash: sulfur dioxide (SO_2), nitrogen dioxide (NO_2), and particulate matter finer than $10\ \mu\text{m}$ in aerodynamic diameter (PM_{10}). As a result of the study, on August 19, 2005, the Virginia Department of Environmental Quality (VDEQ) issued a letter to Mirant requesting that Mirant "undertake such action as is necessary to ensure protection of human health and the environment, in the area surrounding the Potomac River Generating Station, including the potential reduction of levels of operation, or potential shutdown of the facility." On August 24, 2005, in response to VDEQ's August 19, 2005, letter, Mirant decided to shut down all five generating units at the Plant.

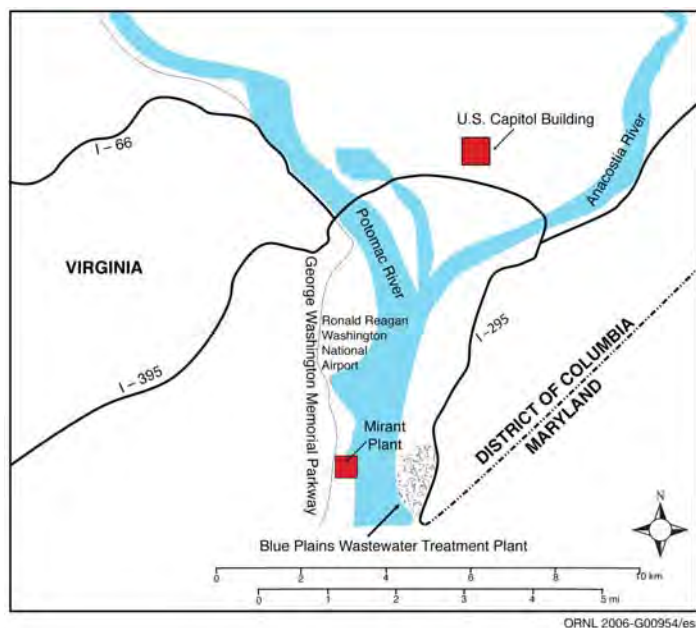


Figure S-1. The location of the Plant in relation to the central Washington, D.C. area.

¹ The September 23, 2004, judicial consent decree (EPA 2004) defined downwash as "the effect that occurs when aerodynamic turbulence induced by nearby structures causes pollutants from an elevated source (such as a smokestack) to be mixed rapidly towards the ground resulting in higher ground-level concentrations of pollutants."

DOE Action

On August 24, 2005, the District of Columbia Public Service Commission (DCPSC) filed an Emergency Petition and Complaint (“Petition”) with DOE pursuant to Section 202(c) of the FPA. The Petition requested the Secretary of Energy to find that an emergency existed under Section 202(c) of the FPA and to issue an order directing Mirant to continue operation of the Plant. Section 202(c) of the FPA authorizes DOE, upon determination that an emergency exists, to “require by order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest.” The basis of the DCPSC’s Petition was that the shutdown of the Plant had a drastic and potentially immediate effect on the reliability of the electricity supply of the Central D.C. area.

After receiving the Petition, DOE spent four months reviewing the facts to gather information on the shutdown of the Plant and its effect on the reliability of the Central D.C. electricity system. DOE met with private entities responsible for electricity transmission in the Central D.C. area and the regional electricity system to determine the role of the Plant in electricity reliability. DOE also met with officials from the Environmental Protection Agency (EPA) to understand the environmental situation posed by the Plant’s operation, particularly with regard to the NAAQS. Meanwhile, on September 21, 2005, Mirant unilaterally restarted the Plant’s unit 1 in an 8-8-8 capacity (that is, in any given 24-hour period, the unit ran for 8 hours at its maximum level, 8 hours at its minimum level, and did not run for 8 hours). Mirant also began experimental use of measures to control SO₂, specifically combustion of low-sulfur coal and injection of trona (a substance similar to baking soda) into flue gases.

During its investigation, DOE learned of the Plant’s key role in providing electricity reliability to the Central D.C. area. The Plant is one of only three sources of electricity to the Central D.C. area. The other sources are two 230-kV transmission lines that deliver electricity from other regional generating sources. The Potomac Electric Power Company (Pepco) is in the process of installing two additional 230-kV transmission lines to the Central D.C. area that will provide a high level of electricity reliability to the area even in the absence of the Plant. These lines are currently expected to be placed in service in June 2007. Until then, if the Plant is not available to generate electricity and one of the two existing transmission lines goes out of service (either unexpectedly or for maintenance), the Central D.C. area would only be served by the remaining line. If the remaining line then failed, a blackout would occur, affecting many government agencies; a large number of residents and workers; and hospitals, police, and fire facilities. Since 2000, there have been 34 one-line planned outages, seven one-line unplanned outages, and two times where both lines failed simultaneously. Indeed, on December 15, 2005, during DOE’s investigation, one of the 230-kV transmission lines failed unexpectedly, and the supply of electricity to the Central D.C. area depended solely on the remaining line until the morning of December 16, 2005.

After DOE's investigation, on December 20, 2005, the Secretary issued the Order stating:

I find that in the circumstances presented here, an emergency exists that justifies the issuance of a section 202(c) order. My determination is not based on any single factor, but on the combination of all relevant facts and circumstances. In particular, I find that an emergency exists because of the reasonable possibility an outage will occur that would cause a blackout, the number and importance of facilities and operations in our Nation's Capital that would be potentially affected by such a blackout, the extended number of hours of any blackout that might in fact occur, and the fact that the current situation violates applicable reliability standards.

DOE's Order did not direct Mirant to simply generate full power at the Plant, even though continuous, unrestricted, operation of the Plant, at all times, was requested in the Petition and would have assured a high level of electricity reliability to the Central D.C. area. Instead, the Order sought to strike an appropriate balance between environmental concerns and electricity reliability by directing Mirant to operate the Plant, but only in certain circumstances and only to limited capacity. Specifically, the Order required Mirant to (1) operate the Plant to produce the amount of power necessary to meet demand in the Central D.C. area during a planned or unplanned outage of one of the 230-kV lines and (2) in situations where both 230-kV lines are functioning, keep as many generating units in operation and take all other measures to reduce the start-up time of units not in operation for the purpose of providing electricity reliability, without causing an exceedance of the NAAQS. The Order further required Mirant to utilize pollution control equipment and measures to the maximum extent possible to minimize the magnitude and duration of any exceedance of the NAAQS during a planned or unplanned transmission line outage. The Order also contemplated continued DOE cooperation with EPA and suggested that DOE would modify the Order at a later date if EPA decided to issue an order to Mirant.

On June 1, 2006, EPA issued an Administrative Compliance Order (ACO) to Mirant. The ACO directs Mirant to operate the Plant under conditions specified in the DOE Order during line outage situations, but requires Mirant to take all reasonable steps to limit SO₂, PM₁₀, and NO_x emissions and to optimize use of trona to minimize SO₂ emissions. In non-line outage situations (i.e., in the normal course of operation), the ACO authorizes Mirant to operate the Plant under "daily predictive modeling" after certain conditions are met. Under daily predictive modeling Mirant is to model a specific operating mode for the Plant based on predicted weather conditions for the following day and operate under that mode only where the daily modeling run demonstrates that the Plant will not cause or contribute to a modeled exceedance of the 3-hr and 24-hr SO₂ and PM₁₀ NAAQS. The ACO also requires Mirant to maintain alarms that alert the Plant operators if monitored average concentrations reach 80% of the standards for SO₂, including the annual SO₂ standard. In addition, the ACO requires Mirant to install and operate six new SO₂ ambient monitoring stations in the vicinity where elevated pollutant concentrations have been predicted and to conduct actual monitoring of ambient SO₂ concentrations. On

June 2, 2006, DOE directed Mirant to operate under the ACO during non-line outage situations, for the purpose of providing electricity reliability, and to continue operation in accordance with the DOE Order in line-outage situations.

DOE believes that the Order and the ACO are the product of the best available balance between providing electricity reliability to the Central D.C. area and protecting the environment and human health in Alexandria, Virginia, until the additional 230-kV lines are in service. The Order and the ACO both contain provisions to prevent NAAQS exceedances in the normal course of operation of the Plant. The only time a possible exceedance of the NAAQS is contemplated is during line-outage situations. In addition, while unplanned transmission line outages cannot be predicted, planned transmission line outages are scheduled in 2006-2007 for periods of time when demand for electricity in the Central D.C. area (and hence emissions from the Plant) is at its lowest. The 2006 amended judicial consent decree, after it is implemented, will provide limitations on NO_x emissions from the Plant.

NEPA Process and this SEA

Major Federal actions significantly affecting the human environment generally call for DOE to prepare an EIS before taking the action to analyze impacts in compliance with NEPA. However, in emergency situations, pursuant to 40 CFR 1506.11, the CEQ's NEPA regulations provide that agencies consult with CEQ to determine what alternative arrangements the agency will take in lieu of preparing an EIS. Before issuing the Order, DOE consulted with CEQ pursuant to 40 CFR 1506.11. As part of its "alternative arrangements plan," DOE agreed to provide opportunity for public involvement, continue Agency consultation, and identify alternatives for mitigation (DOE 2006). In addition, as an alternative to an EIS, CEQ agreed to preparation of this SEA. This SEA does not include an impact assessment of alternative actions that DOE might have taken instead of issuing its Order on December 20, 2005. DOE will not issue a record of decision (ROD) based on this SEA.

In the January 20, 2006, *Federal Register* notice announcing the alternative arrangements (DOE 2006), DOE requested public comments on issues to be addressed in the SEA. Comments were provided by the following organizations: the Mount Vernon group and the Virginia Chapter of the Sierra Club; the Southern Environmental Law Center on behalf of itself and the American Lung Association of Virginia; the City of Alexandria; and the Institute for Public Representation on behalf of the Potomac Riverkeeper, Inc., the Patuxent Riverkeeper, and the Anacostia Riverkeeper at Earth Conservation Corps. Commentors on the notice expressed particular concern about the following issues that are within the scope of this SEA:

- impacts on health of increased particulate emissions, especially particulate matter smaller than 2.5 microns (PM_{2.5}), and of increased emissions of trace metals and hazardous air pollutants (especially arsenic, beryllium, lead, chromium, cadmium, nickel, and mercury);

- the potential for any increased emissions of SO₂ and NO_x to contribute to acid rain, nutrient loading to aquatic systems, and deposition of heavy metals, and the subsequent impacts on the aquatic resources of the Chesapeake Bay and several of its tributaries, specifically the Potomac, Anacostia, and Patuxent rivers;
- impacts of trona utilization; and
- potential mitigation measures, such as use of existing transmission lines along the railroad rights-of-way of the National Railroad Passenger Corporation (“AMTRAK”) and CSX Corporation and notification of nearby residents about potential NO_x exceedances.

A commentor also expressed concern about possible adverse effects of trona utilization on Plant equipment. This concern is not addressed because it is not considered to be an environmental impact.

The aim of this SEA is to describe the impacts resulting from the Order and from potential future alternative actions DOE may take in this matter. Such potential future alternative actions include allowing the Order to expire; extending the Order until the expected June 2007 in-service date of the two additional 230-kV transmission lines (or until December 2007, to account for unlikely, but possible, delays in installation); or extending the Order in modified form to include measures to mitigate impacts. Because allowing the Order to expire would place the Central D.C. area at risk of a potential blackout, this SEA describes potential impacts associated with a blackout. Potential mitigation alternatives discussed in this SEA include measures to, among other things, reduce demand for electricity in the Central D.C. area, require storage of sufficient trona at the Plant, and expedite the installation of the additional 230-kV transmission lines.

In order to give the reader a contextual way to understand the assessed impacts attributable to the Order and from a potential extension of the Order until the two new 230-kV transmission lines are in service, DOE uses assessed impacts from two different earlier Plant operating modes as a basis for comparison: the “pre-shutdown” mode of operations and the “pre-Order” operating mode. The “pre-shutdown” operating mode is based on operations in the year preceding the August 24, 2005, shutdown. The “pre-Order” mode is based on operation of the Plant during its restart of unit 1 in the 8-8-8 operating mode (approximately September - December 2005).

DOE’s assessment of the effects of Plant operations considered the following resource areas and impact topics:

- Effects of any increased *air emissions*;
- *Health* effects on Plant workers and the public of any increased air pollution;
- Effects on *water quality* due to atmospheric deposition of air pollutants from the Plant and changes in Plant water use and releases;
- *Ecological* effects due to acid deposition, changes in water quality, and changes in water use, including impacts to special status species;
- *Waste management* impacts, particularly impacts of trona utilization;

- *Transportation impacts* from increased shipping of coal and trona to the Plant and of wastes away from the Plant; and
- *Environmental justice impacts*.

It is important to understand the process DOE used to assess impacts from the Order and from a potential additional extension of the Order. Understanding DOE's approach for modeling air quality impacts is particularly important because (1) air quality is the most significant environmental concern associated with the Plant's operation and (2) many other impacts, including impacts to human health, are based on modeled estimates of air impacts. For its air analysis DOE used EPA's AERMOD model to assess modeled concentrations of SO₂ and PM₁₀ as a result of the Order (split into two time periods: before the ACO and after the ACO) and a potential extension of the Order (until July 2007 and December 2007). DOE focused on modeling concentrations of SO₂ and PM₁₀ because the original downwash study that prompted the shutdown of the Plant emphasized SO₂, PM₁₀, and NO_x (and the amended judicial consent decree between EPA and Mirant [EPA 2006g] deals with NO_x.) In modeling concentrations of SO₂ and PM₁₀, DOE used several simplifications and made a number of key assumptions that are essential to understand before interpreting the modeled results:

- *Assumptions in Modeling*
 - DOE's modeling of SO₂ and PM₁₀ assumed weather conditions from 2001 because EPA had shown that 2001 resulted in predictions of more adverse air quality than any of the other years during the period from 2000 through 2004. Therefore, DOE's modeling results likely overestimate impacts.
 - DOE's assessment of impacts to the health of people living near the Plant is based on estimated exposures to PM_{2.5}. DOE used air dispersion modeling for PM₁₀ to estimate exposures to PM_{2.5}. Therefore, to the extent that DOE's modeled air quality results overestimate impacts, the health results also likely overestimate impacts. In addition, DOE did not analyze factors such as health status or activity level that affect the likelihood of actual health impacts to specific individuals. Consequently, the results of DOE's health impact analysis represents an estimate of the impact to the population, rather than the likely impact to any specific individual.
- *Assumptions and Simplifications about Operations*
 - For the period from December 21, 2005, through March 31, 2006, DOE used hourly emissions data provided by Mirant to model SO₂ and PM₁₀ emissions. (For the two days for which data were not provided, DOE assumed operations were identical to the preceding day.) To model the air quality impacts of operations during the period April 1 through May 31, 2006, DOE assumed that Mirant operated the Plant to the maximum level described in the operating plan supplements that Mirant provided to DOE.

- For operations during daily predictive modeling, DOE assumed that the Plant would generate the maximum allowed power by using a combination of increased trona injection and reduced power levels to assure that its operations would not contribute to an exceedance of the 24-hour-average NAAQS limit for SO₂ concentrations in the normal course of business (i.e., no line outage). DOE did not simulate predictive modeling for the 3-hour SO₂ standard because the computational effort required to calculate average concentrations for all possible 3-hour periods for each of the over 1,700 modeled locations near the Plant was judged to be excessively large for the information to be gained. Consequently, the SEA reports modest modeled exceedances of the 3-hour SO₂ standard that are not expected to actually occur. The SEA also reports exceedances of the annual standard because operating close to the 24-hour limit day after day raises the long-term average. However, because the ACO requires Mirant to monitor SO₂ concentrations and adjust operation of the Plant to meet SO₂ standards for all averaging periods, actual exceedances of the annual standard are not expected to occur.

Preliminary data from the six new SO₂ monitoring stations that Mirant installed during the summer of 2006, pursuant to the ACO, provides an initial look at actual impacts from the Plant under the ACO's daily predictive modeling. DOE's modeling results are not directly comparable to the monitored data because DOE's modeling used average emissions and historical weather data rather than current-year data. However, monitored data can be compared with the follow-up modeling that Mirant is conducting under the ACO, using actual concurrent emissions and weather data. For the period June 17, 2006, to September 17, 2006, the maximum monitored daily-average SO₂ concentration for the monitors ranged from 4 to 63 µg/m³, whereas Mirant's follow-up modeling gave maximum daily-average SO₂ concentrations from 25 to 570 µg/m³. Thus, monitored concentrations of SO₂ are much lower than Mirant's follow-up modeled concentrations. EPA will be evaluating the reasons for this large discrepancy between the actual monitored data and follow-up modeling throughout the course of the ACO. Should DOE extend the Order on December 1, 2006, DOE will make monitored data (as submitted by Mirant to EPA under the ACO) available on the website it maintains to provide information about this matter, <http://www.oe.energy.gov/permitting/372.htm>.

Table S.1 summarizes the assessed impacts of the Order, both before and after the initiation of daily predictive modeling. It also includes impacts of the temporary extension of the Order and a potential additional extension of the Order until December 2007, assuming a 6-month delay in the installation of the additional 230-kV lines. Finally, the table presents the assessed impacts associated with the "pre-shutdown" and "pre-Order" modes of operation of the Plant to give the reader a basis for comparison.

Table S.1 Summary of impacts of Plant operations (See text for details.)

Resources and Topics	Pre-shutdown (prior to August 24, 2005)	Pre-Order (Sept. - Dec. 20, 2005)	Order (Dec. 20, 2005 - Oct. 1, 2006)	Temporary extension of Order (until Dec. 1, 2006) and potential extension until Dec. 2007 ¹
<i>AIR QUALITY</i>				
SO ₂	Modeled maximum concentration values for SO ₂ in ambient air exceed NAAQS limits for all averaging periods (i.e., 3-hour, 24-hour, and annual).	Modeling shows no exceedance of NAAQS limit for any averaging period.	For operations before the commencement of daily predictive modeling (i.e., before July 1, 2006), there are no modeled SO ₂ or NO _x exceedances during non-line outage situations. For operations during line outages (21 days in January 2006) modeled maximum concentration values for SO ₂ in ambient air exceed SO ₂ NAAQS limits for all averaging periods.	For operations during non-line outage periods, modeling shows no exceedances of 24-hour average SO ₂ NAAQS limit because of requirements of predictive modeling. Modeling shows exceedances for other averaging periods, but because the ACO requires compliance with SO ₂ NAAQS in non-line outage situations, actual exceedances are not expected. For operations during line outages, modeled maximum concentration values for SO ₂ in ambient air exceed SO ₂ NAAQS limits for all averaging periods.
		For operations after the commencement of daily predictive modeling (i.e., starting July 1, 2006), modeling shows no exceedances of 24-hour average SO ₂ NAAQS limit because of requirements of predictive modeling. Modeling shows exceedances for other averaging periods, but because the ACO requires compliance with SO ₂ NAAQS in non-line outage situations, actual exceedances are not expected.		

Table S.1 (Continued)

Resources and Topics	Pre-shutdown (prior to August 24, 2005)	Pre-Order (Sept. - Dec. 20, 2005)	Order (Dec. 20, 2005 - Oct. 1, 2006)	Temporary extension of Order (until Dec. 1, 2006) and potential extension until Dec. 2007 ¹
PM ₁₀	Modeled maximum concentration values for PM ₁₀ in ambient air meet NAAQS annual standard but exceed limit for 24-hour averaging period. ²	Modeled maximum concentration values for PM ₁₀ in ambient air meet NAAQS standards for both the annual and 24-hour averaging periods. ³		
PM _{2.5}	Background concentrations measured by VDEQ while the Plant was operating at pre-shutdown levels are below the current NAAQS limit for 24-hour averaging period (65 µg/m ³) and are slightly below the current NAAQS annual limit (15 µg/m ³), but exceed the NAAQS limit for the 24-hour averaging period (35 µg/m ³) that will take effect in December 2006. As a result of the background contribution, estimated maximum concentration values in ambient air (including background) for all operating modes exceed the NAAQS annual limit and the December 2006 limit for the 24-hour averaging period, both at ground level and the top of Marina Towers. Adding estimated Plant contributions to background concentrations involves some double counting of Plant effects.			
	Estimated maximum concentration values in ambient air (including background) at ground level and the top of Marina Towers exceed current and future NAAQS limits for both 24-hour and annual averaging periods.	Estimated maximum concentration values in ambient air (including background) at ground level and the top of Marina Towers are lower than for pre-shutdown operations and meet the current NAAQS limit for the 24-hour averaging period, but exceed the annual and 24-hr limits that will take effect in December 2006.	Estimated maximum concentration values in ambient air (including background) at ground level are lower than for pre-shutdown operations but higher than for pre-Order operations and meet the current NAAQS limit for the 24-hour averaging period but exceed the annual and 24-hr limits that will take effect in December 2006. Estimated maximum concentration values at the top of Marina Towers are lower than for pre-shutdown operations, but exceed current and future NAAQS limits for both 24-hour and annual averaging periods.	

Table S.1 (Continued)

Resources and Topics	Pre-shutdown (prior to August 24, 2005)	Pre-Order (Sept. - Dec. 20, 2005)	Order (Dec. 20, 2005 - Oct. 1, 2006)	Temporary extension of Order (until Dec. 1, 2006) and potential extension until Dec. 2007 ¹
PM _{2.5} (continued)	Plant contributions to ground-level PM _{2.5} : 38 µg/m ³ for 24-hr 5.7 µg/m ³ for annual	Plant contributions to ground-level PM _{2.5} : 9.2 µg/m ³ for 24-hr 2.0 µg/m ³ for annual	Plant contributions to ground-level PM _{2.5} : 25 µg/m ³ for 24-hr 2.4 µg/m ³ for annual	Plant contributions to ground-level PM _{2.5} : 23 µg/m ³ for 24-hr 4.0 µg/m ³ for annual
	Plant contributions to PM _{2.5} at the top of Marina Towers: 76 µg/m ³ for 24-hr 7.8 µg/m ³ for annual	Plant contributions to PM _{2.5} at the top of Marina Towers: 4.8 µg/m ³ for 24-hr 1.0 µg/m ³ for annual	Plant contributions to PM _{2.5} at the top of Marina Towers: 41 µg/m ³ for 24-hr 3.9 µg/m ³ for annual	Plant contributions to PM _{2.5} at the top of Marina Towers: 43 µg/m ³ for 24-hr 5.7 µg/m ³ for annual
Contributions to ozone pollution from NO _x	Operations estimated to emit 2,300 tons ³ of NO _x (which contributes to formation of ozone) over 285 days (rate of about 3,000 tons/yr)	Operations estimated to emit 640 tons of NO _x over 285 days (rate of about 820 tons/yr)	Operations estimated to emit 2,000 tons of NO _x over 285 days (rate of about 2,600 tons/yr)	Operations estimated to emit 3,700 tons of NO _x over 15 months (rate of about 3,000 tons/yr)
Mercury emissions	Operations estimated to emit mercury at a rate of 116 lb/yr or 91 lb over 285 days ³	Operations estimated to emit 21 lb mercury over 285 days (rate of about 28 lb/yr)	Operations estimated to emit 79 lb mercury over 285 days (rate of about 101 lb/yr)	Operations estimated to emit mercury at a rate of 116 lb/yr or 146 lb over 15 months
Carbon monoxide and lead	Because ambient concentrations of carbon monoxide and lead are far below NAAQS limits and because coal plants are not important sources of either pollutant, DOE did not model Plant contributions to ambient levels for either pollutant.			
Contributions to global climate change	Operations estimated to release CO ₂ (a greenhouse gas that contributes to global warming) at a rate of 2,000,000 tons/yr from coal use	Operations estimated to release CO ₂ at a rate of 488,800 tons/yr from coal use	Operations estimated to release CO ₂ at a rate of 1,766,500 tons/yr from coal and trona use	Operations estimated to release CO ₂ at a rate of 2,007,500 tons/yr from coal and trona use

Table S.1 (Continued)

Resources and Topics	Pre-shutdown (prior to August 24, 2005)	Pre-Order (Sept. - Dec. 20, 2005)	Order (Dec. 20, 2005 - Oct. 1, 2006)	Temporary extension of Order (until Dec. 1, 2006) and potential extension until Dec. 2007 ¹
HUMAN HEALTH				
Premature mortality due to air pollution exposure	Expected incidence of premature mortality among the 144,000 adults in 36-mi ² area ³ around the Plant of 3.8 per year	Expected incidence of premature mortality among the 144,000 adults in 36-mi ² area around the Plant of 0.77 per year	Expected incidence of premature mortality among the 144,000 adults in 36-mi ² area around the Plant of 1.3 over 285-day duration of the Order (annual rate of 1.7)	Expected incidence of premature mortality among the 144,000 adults in 36-mi ² area around the Plant of 2.9 over 15-month duration of the potential extension (annual rate of 2.3)
WATER QUALITY				
Nitrogen loading to Chesapeake Bay	Operations deliver nitrogen to the Bay at an estimated rate of 170,000 lb/yr	Operations deliver nitrogen to the Bay at an estimated rate of 47,000 lb/yr	Operations deliver nitrogen to the Bay at an estimated rate of 150,000 lb/yr	Operations deliver nitrogen to the Bay at an estimated rate of 170,000 lb/yr
Acid deposition	Plant emissions of SO ₂ and NO _x contribute to regional acid deposition.	SO ₂ and NO _x emissions are 28% of pre-shutdown levels	NO _x emissions are 87% of pre-shutdown levels; SO ₂ emissions are less than 45% of pre-shutdown levels	NO _x emissions are similar to pre-shutdown levels, but SO ₂ emissions are 50% of pre-shutdown levels
Effects of changes in Plant water use and releases	Negligible impacts to water quality in nearby watersheds, because these watersheds are well buffered against acid rain. Effects of many years of Plant operations are among the natural and human factors reflected in the existing water quality conditions of the Potomac River	Reduced water and thermal discharge rates, compared with pre-shutdown operations, could contribute to improved water quality in the Potomac River	Impacts intermediate between pre-Order and pre-shutdown operations	Impacts similar to pre-shutdown operations

Table S.1 (Continued)

Resources and Topics	Pre-shutdown (prior to August 24, 2005)	Pre-Order (Sept. - Dec. 20, 2005)	Order (Dec. 20, 2005 - Oct. 1, 2006)	Temporary extension of Order (until Dec. 1, 2006) and potential extension until Dec. 2007 ¹
ECOLOGICAL RESOURCES				
Acid deposition	Acid deposition resulting from Plant operations has negligible impacts on terrestrial and aquatic biological resources because (1) the soils in the nearby river and stream watersheds where emissions from the Plant are likely to fall are well buffered and (2) vegetation has actively grown near and next to the Plant even at "pre-shutdown" levels.			
Changes in water quality	Ecological changes to the Potomac River and Chesapeake Bay due to changes in nutrient loading induced by the Order or a potential extension of the Order would be minimal.	No effects from trona (assessment assumes no use of trona).	Selenium and arsenic leached from solid wastes produced with trona use could adversely affect biota in Mataponi Creek. Monitoring of collected landfill leachate and stormwater for selenium should identify the potential for problems before discharges occur, but the current discharge permit does not require monitoring for arsenic.	
Changes in water use	Effects of Plant operations under the Order or a potential extension of the Order through December 2007 would not have a major impact on aquatic biota, although the impacts from entrainment and impingement would be greater than for the "pre-Order" mode.			
Special status species	No adverse impacts to any special status species would be expected to result from Plant operations.			

Table S.1 (Continued)

Resources and Topics	Pre-shutdown (prior to August 24, 2005)	Pre-Order (Sept. - Dec. 20, 2005)	Order (Dec. 20, 2005 - Oct. 1, 2006)	Temporary extension of Order (until Dec. 1, 2006) and potential extension until Dec. 2007 ¹
WASTE MANAGEMENT				
Solid waste	With indefinite continuation of Plant operations in pre-shutdown mode, the Mirant Brandywine ash landfill would be able to receive fly ash until mid-2012.	With indefinite continuation of Plant operations in pre-Order mode, the Mirant Brandywine landfill would be able to receive fly ash until mid-2015.		With indefinite continuation of Plant operations at operating levels under the Order, including use of trona, the Mirant Brandywine ash landfill would be able to receive fly ash until early 2010.
	Waste characteristics would be unchanged.	Waste characteristics would be unchanged (assessment assumes no use of trona).		Trona in Plant solid wastes may increase the leaching of selenium and arsenic from the landfill. Current monitoring requirements at the landfill include monitoring for selenium in collected leachate and stormwater before water is discharged to surface water, but do not include monitoring for arsenic. Groundwater monitoring does not include selenium or arsenic.
TRANSPORTATION				
Impacts from road and rail traffic	Neither rail nor truck traffic associated with Plant operations have an important effect on local traffic near the Plant.			
	Transport of Plant fly ash to the Mirant Brandywine ash landfill contributes to existing traffic problems on Maryland Route 381, and increased traffic associated with operations under the Order, including the temporary extension of the Order and any potential extension of the Order increases this effect. The State Highway Administration is requiring that Mirant address problems at certain intersections along Maryland Route 381 that have been rated as having "failing" levels of service, and Maryland-National Capital Park and Planning Commission staff have recommended ways to address traffic impacts on North Keys Road.			

Table S.1 (Continued)

Resources and Topics	Pre-shutdown (prior to August 24, 2005)	Pre-Order (Sept. - Dec. 20, 2005)	Order (Dec. 20, 2005 - Oct. 1, 2006)	Temporary extension of Order (until Dec. 1, 2006) and potential extension until Dec. 2007 ¹
ENVIRONMENTAL JUSTICE				
Impacts to minority and low-income populations	Because of their proximity to the Plant, residents of block groups 1 and 2 (which are neither low-income nor minority populations) experience higher air pollution from Plant emissions than residents of block groups 3 (which is identified as a low-income population) and 4 (which is identified as a minority population). DOE has not identified any different or unique ways that these or other minority and low-income populations in the area could be exposed to Plant air pollutants or otherwise affected by the Order or its potential extension. Consequently, the minority and low-income populations in block groups 3 and 4 do not suffer “disproportionately high and adverse human health or environmental effects” related to air pollutant emissions from the Plant.			

¹ For several resources and topics, emissions and impacts are greater under an extension of the Order than under the Order because during the initial months of the Order the Plant operated at lower levels than result from daily predictive modeling.

² EPA’s October 17, 2006, rule making on NAAQS for particulate matter (EPA 2006j) revoked the annual PM₁₀ standard, effective December 18, 2006.

³ To convert tons to metric tons, multiply by 0.91. To convert lbs to kg, multiply by 0.45. To convert square miles to square km, multiply by 2.60.

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Special Environmental Analysis

**For Actions Taken under U.S. Department of Energy
Emergency Orders Regarding Operation of the
Potomac River Generating
Station in Alexandria, Virginia**

DOE/SEA-04

**U.S. Department of Energy
Washington, D.C.**

November 2006

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ACRONYMS AND ABBREVIATIONS

µg	micrograms (i.e., millionths of a gram)	MES	Model Evaluation Study
µm	micrometers (i.e., millionths of a meter)	mg	milligrams (i.e., thousandths of a gram)
ACO	Administrative Compliance Order	mi	mile
Btu	British thermal unit	mi ²	square mile
C	Celsius	min	minute
CAA	Clean Air Act	MSL	mean sea level
CEQ	Council on Environmental Quality	MW	megawatts
CFR	<i>Code of Federal Regulations</i>	MWh	megawatt-hour
cm	centimeter	NAAQS	National Ambient Air Quality Standards
CO	carbon monoxide	NEPA	National Environmental Policy Act
CO ₂	carbon dioxide	NMFS	National Marine Fisheries Service
CT	census tract	NO ₂	nitrogen dioxide
D.C.	District of Columbia	NO _x	oxides of nitrogen
DCPSC	District of Columbia Public Service Commission	NPDES	National Pollutant Discharge Elimination System
DOE	U.S. Department of Energy	O ₃	ozone
EPA	U.S. Environmental Protection Agency	Pb	lead
ESA	Endangered Species Act	Pepco	Potomac Electric Power Company
F	Fahrenheit	PJM	PJM Interconnection, LLC
FAA	Federal Aviation Administration	Plant	Mirant's Potomac River Generating Station (in Alexandria, Virginia)
FERC	Federal Energy Regulatory Commission	PM	particulate matter
FPA	Federal Power Act	PM _{2.5}	particulate matter with an aerodynamic diameter less than or equal to 2.5 µm
FR	<i>Federal Register</i>	PM ₁₀	particulate matter with an aerodynamic diameter less than or equal to 10 µm
ft	feet	ppb	parts per billion
ft ²	square feet	ppm	parts per million
FWS	U.S. Fish and Wildlife Service	RCRA	Resource Conservation and Recovery Act
gal	gallons	ROD	<i>Record of Decision</i>
ha	hectare	SEA	special environmental analysis
hr	hour	SIP	state implementation plan
kg	kilogram	SO ₂	sulfur dioxide
km	kilometer	TCLP	Toxicity Characteristic Leaching Procedure
km ²	square kilometer	U.S.	United States
kV	kilovolt	U.S.C.	United States Code
L	liter	VDEQ	Virginia Department of Environmental Quality
lb	pound(s)	yd ³	cubic yard
LLC	Limited Liability Company	yr	year
LOS	level-of-service		
m	meter		
m ²	square meter		
m ³	cubic meter		
MBtu	million British thermal units		

EXPONENTIAL NOTATION: Some values in the text and tables of this document are expressed in exponential notation. An exponent is the power to which the expression, or number, is raised. This form of notation is used to conserve space and to focus attention on comparisons of the order of magnitude of the numbers (see examples):

1×10^4	=	10,000
1×10^2	=	100
1×10^0	=	1
1×10^{-2}	=	0.01
1×10^{-3}	=	0.001

Metric Conversions Used in this Document:

Multiply	By	To Obtain
<i>Length</i>		
inch (in.)	2.54	centimeters (cm)
feet (ft)	0.30	meters (m)
yards (yd)	0.91	meters (m)
miles (mi)	1.61	kilometers (km)
<i>Area</i>		
acres (ac)	0.40	hectares (ha)
square feet (ft ²)	0.093	square meters (m ²)
square yards (yd ²)	0.84	square meters (m ²)
square miles (mi ²)	2.60	square kilometers (km ²)
<i>Volume</i>		
gallons (gal)	3.79	liters (L)
cubic feet (ft ³)	0.028	cubic meters (m ³)
cubic yards (yd ³)	0.76	cubic meters (m ³)
<i>Weight</i>		
ounces (oz)	28.4	grams (gm)
pounds (lb)	0.45	kilograms (kg)
short ton (ton)	0.91	metric ton (t)

1. PURPOSE AND NEED FOR THE DOE ACTION

1.1 Introduction

This special environmental analysis (SEA) focuses on the environmental impacts of operations at the coal-fired Potomac River Generating Station (the “Plant”) in Alexandria, Virginia, as a result of a U.S. Department of Energy (DOE or “Department”) emergency order (the “DOE Order” or “Order”) (Appendix A) issued on December 20, 2005, pursuant to Section 202(c) of the Federal Power Act (FPA)¹. The Plant is owned by Mirant Corporation and its wholly owned subsidiary, Mirant Potomac River, LLC (collectively referred to herein as Mirant). (See text box.)

On August 24, 2005, Mirant shut down operation of the Plant to respond to concerns about the Plant’s impacts on air quality. (See Section 1.3.3.) On August 24, 2005, DOE received an Emergency Petition and Complaint from the District of Columbia (D.C. or District) Public Service Commission (DCPSC 2005). That petition requested DOE to direct Mirant to continue operation of the Plant. The basis for the petition was that shutdown of the Plant reduced the reliability of the electrical supply (Section 1.3.1) to much of the central business district of the District of Columbia, many Federal institutions, the Georgetown area in D.C., other portions of Northwest D.C., and the D.C. Water and Sewer Authority's Blue Plains Wastewater Water Treatment Plant (collectively referred to herein as the “Central D.C. area”), placing these electrical customers at risk of a blackout (DCPSC 2005).

After receiving the petition from the D.C. Public Service Commission, DOE undertook an exhaustive review of the facts. (See Section 1.3.3 for a detailed history.) Based on this

Entities involved in delivering power in the Central D.C. area

Mirant owns and operates electrical power generating plants, including the Potomac River Generating Station in Alexandria, Virginia.

Potomac Electric Power Company (Pepco) owns and operates transmission lines and is responsible for supplying electricity to retail customers in D.C. and parts of Maryland.

PJM Interconnection, LLC (PJM) is the transmission organization responsible for coordinating the regional electric power grid and wholesale electricity market in D.C., Maryland, Virginia, Delaware, New Jersey, West Virginia, and parts of Indiana, Illinois, Kentucky, Michigan, Ohio, Pennsylvania, and Tennessee. PJM keeps the electricity supply and demand in balance by telling power producers how much power to generate.

¹ Section 202(c) of the FPA vests in the Secretary of Energy the authority to issue an order when “an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of the fuel or water for generating facilities, or other causes...” [16 U.S.C. Section 824a(c)]

extensive evaluation, the Secretary of the Energy on December 20, 2005, issued Order 202-05-03 (the “DOE Order”) directing Mirant to generate electricity at the coal-fired Plant under certain, limited circumstances.

DOE is issuing this SEA in compliance with the “alternative arrangements” plan agreed upon with the Council on Environmental Quality (CEQ) pursuant to 40 CFR 1506.11. This SEA covers a period of about 24 months beginning with the issuance of the Order. The time period for DOE’s original Order ended at 12:01 am on October 1, 2006; on September 28, 2006, the Secretary of Energy extended the Order for two months, until 12:01 am on December 1, 2006. However, this SEA covers the full 24-month period at the end of which the Potomac Electric Power Company (Pepco) (text box) expects to have completed construction of new transmission lines that will provide additional electrical service to customers in the Central D.C. area.

1.2 Purpose and Need for Agency Action

The purpose and need for DOE’s action was to respond to the emergency reliability situation that had been brought on by shutdown of operations at the Mirant Potomac River Generating Station.

1.3 Background

1.3.1 Electrical Reliability

The Plant has been operating since 1949. It is one of three sources that provide electricity to Central D.C. area customers. The other sources are two 230,000-volt (230-kV) transmission lines that deliver electricity from other regional generating sources. Two additional generating stations exist in close physical proximity to the Central D.C. area, but they are not connected by transmission lines that allow the electricity they produce to be delivered to that area. Thus, if the Plant is not available to generate electricity and one of the two transmission lines serving the Central D.C. area goes out of service, electricity would be supplied to that area by only the one remaining transmission line. Should the remaining line fail for any reason, a potentially extended blackout would occur in the Central D.C. area. If both lines are down and one of them could not be brought back into service immediately, it would take at least 28 hours to bring the Plant into full operation, during which time much of the Central D.C. area would be without electricity. Transmission line outages can be either planned in order to perform periodic maintenance or unexpected. The duration of an outage can be several days or weeks for maintenance or up to several weeks in the event of a major, unexpected equipment failure.

An important consideration in issuing the Order was the facilities and functions that would be adversely affected by an extended blackout. The Central D.C. area includes facilities of

all three branches of the U.S. government that are critically important to the Nation's national security, law enforcement, and regulatory functions. The Central D.C. area also includes hundreds of thousands of residents and workers and many public safety and protection facilities (e.g., hospitals, police and fire stations). Moreover, within 24 hours of a Central D.C. blackout the Blue Plains Wastewater Treatment Plant would begin to discharge untreated sewage into the Potomac River. Thus, an extended blackout would severely impact critical portions of the Nation's government with potentially adverse national effects. It would also result in hardship and potential physical risk to many people from loss of heat or cooling, elevator outages, medical equipment failure, and other causes.

In 2005 Pepco received permission from the D.C. Public Service Commission to construct two additional 230-kV lines that would supply electricity to the Central D.C. area and two new 69-kV lines that would supply electricity to the Blue Plains Wastewater Treatment Plant. The two 69-kV lines have since been constructed. Once the new 230-kV lines are completed, these lines will provide a high level of electricity reliability in the Central D.C. area, even in the absence of production from the Plant. However, it could be mid- to late-2007 before the new lines are installed and operating. Pepco's schedule for completing installation of the new transmission lines has the lines going into service in June 2007.

1.3.2 Environmental and Health Issues

Residents in the area of the Plant have been concerned about the environmental and health impacts of its air emissions for years (SPROL 2005). However, the D.C. Public Service Commission, Pepco, and PJM Interconnection, LLC (PJM) (text box) have contended that there were no actual monitored exceedances of the National Ambient Air Quality Standards (NAAQS) of the Clean Air Act (CAA) during the Plant's operation in the period before Mirant shut it down on August 24, 2005, and that operation of the Plant at full power at any time during that period did not exceed the emissions limits contained in the Plant's operating permit (DOE Order 202-05-03).

1.3.3 Detailed History

This section describes the actions taken by DOE in relation to the DOE Order and to the Plant. Table 1.3-1, at the end of the section, provides a more complete chronology of the major actions and events related to the DOE Order and the Plant.

Mirant and the Virginia Department of Environmental Quality (VDEQ) entered into an Order by Consent on September 23, 2004. Under that order Mirant performed a dispersion modeling analysis to assess the effect of downwash² of air emissions from the Plant and to

² The September 23, 2004, judicial consent decree (EPA 2004) defined downwash as "the effect that occurs (continued...)"

determine whether the Plant could cause or contribute to significant localized exceedances of the NAAQS (ENSR 2005). This study, known as the downwash study, used computer modeling to predict ambient concentrations of pollutants emitted by the Plant under certain weather and atmospheric conditions.

Mirant submitted the results of the downwash study to the VDEQ in August 2005. After reviewing the study, VDEQ sent Mirant a letter dated August 19, 2005, stating that the modeling results showed that under certain atmospheric conditions the Plant's operations could result in, cause, or substantially contribute to modeled violations of the NAAQS for sulfur dioxide (SO₂), oxides of nitrogen (NO_x), and particulate matter with an aerodynamic diameter less than or equal to 10 µm (PM₁₀).

In its August 19, 2005, letter the VDEQ requested “that Mirant *immediately* undertake such action as is necessary to ensure protection of human health and the environment, in the area surrounding the Potomac River Generating Station, including the potential reduction of levels of operation, or potential shutdown of the facility.” (emphasis in original)

In response to the letter from the VDEQ, Mirant chose to shut down all five of the generating units at the Plant on August 24, 2005.

On August 24, 2005, the D.C. Public Service Commission filed an Emergency Petition and Complaint with DOE that requested DOE to issue an emergency order directing Mirant to continue operation of the Plant in order to prevent the risk of a blackout in the Central D.C. area (DCPSC 2005). The Commission also requested that the Federal Energy Regulatory Commission (FERC) issue a similar order under Sections 207 and 309 of the FPA.

Mirant then completed a refined computer modeling study using more realistic scenarios that indicated that the Plant could operate, in a limited fashion, within air quality standards. Thus, on September 21, 2005, Mirant restarted only Unit 1 at the Plant. From that date until the DOE Order was issued, Mirant operated that unit on an 8-8-8 basis – that is, in any given 24-hour period, the unit ran for up to eight hours at its maximum level, ran for eight hours at its minimum level, and did not run for eight hours. Mirant also experimented during this period with using trona (i.e., sodium sesquicarbonate, a naturally occurring substance similar to baking soda) or low-sulfur Colombian coal³, alone or in combination, to control SO₂ emissions in order to determine if such changes would allow simultaneous operation of more than one unit without causing NAAQS exceedances.

² (...continued)

when aerodynamic turbulence induced by nearby structures causes pollutants from an elevated source (such as a smokestack) to be mixed rapidly towards the ground resulting in higher ground-level concentrations of pollutants.”

³ During its experiments with low-sulfur coal from Colombia, Mirant determined that the higher moisture content in this type of coal created multiple operational problems. For example, the Plant was unable to dry the coal sufficiently for the coal pulverizers to maintain adequate throughput rates, and the moisture resulted in reduced efficiency of both the combustion and the heat transfer processes. For these reasons after its initial test of Colombian coal, Mirant decided not to use it any further.

After receiving the Commission's petition, DOE conducted an independent examination of the electricity reliability situation in the Central D.C. area and analyzed the Plant's role in ensuring a reliable supply of electricity to that area (Kirby and Kueck 2005). DOE also consulted with Federal and state officials responsible for environmental compliance (e.g., EPA shared information with DOE regarding NAAQS modeled results and other environmental issues at the Plant) and private entities responsible for electricity transmission. DOE's investigation found that the Plant must be available to run when one of the 230-kV lines is out of service in order to maintain a minimally reliable electric power system, because outage of the remaining line could result in a blackout of the Central D.C. area. DOE's investigation also found that the Plant should be operated in such a way as to minimize the amount of time needed to bring it into full operation to be better able to meet electric reliability needs quickly whenever one of the two 230-kV transmission lines was unexpectedly removed from service.

After DOE's investigation, on December 20, 2005, the Secretary issued the Order stating:

I find that in the circumstances presented here, an emergency exists that justifies the issuance of a section 202(c) order. My determination is not based on any single factor, but on the combination of all relevant facts and circumstances. In particular, I find that an emergency exists because of the reasonable possibility an outage will occur that would cause a blackout, the number and importance of facilities and operations in our Nation's Capital that would be potentially affected by such a blackout, the extended number of hours of any blackout that might in fact occur, and the fact that the current situation violates applicable reliability standards.

DOE's Order directed Mirant to generate electricity at the Plant under certain, limited circumstances and to do so in such a way as to minimize adverse environmental impacts. The Order required Mirant to (1) operate the Plant to produce the amount of power (up to its full capabilities) needed to meet demand in the Central D.C. area during any period in which one or both of the 230-kV lines serving the Central D.C. area were out of service and (2) in situations when both lines are functioning, keep as many generating units in operation and take all other measures to reduce the start-up time of units not in operation, without regard to cost and without causing or significantly contributing to any exceedance of the NAAQS, in order to provide electrical reliability to the Central D.C. area. The Order also required Mirant to submit a plan to DOE within ten days indicating how it would comply with the Order. (See Appendix A for the full text of the Order.)

On December 30, 2005, as required by the DOE Order, Mirant submitted a plan describing how it would comply with the Order. The plan outlined a proposed temporary phase and two options for a proposed intermediate phase: Option A and Option B. All proposals included the use of trona and/or low-sulfur coal to manage air emissions. Mirant stated in its compliance plan that "Option A results in no modeled NAAQS exceedances." Mirant also stated

that “Option B offers dramatically better reliability than Option A, but results in a marginal computer-modeled exceedance of the 24-hour NAAQS for [SO₂], although the 3-hour and annual NAAQS for SO₂ are met. Moreover, that exceedance was modeled to occur infrequently in the course of a year and only on the top floor balconies and the roof of the Marina Towers condominium...” After reviewing Mirant’s compliance plan, DOE instructed Mirant on January 4, 2006, to “immediately take the necessary steps to implement Option A.” Between January and May, the Department continued to weigh other options that were available to Mirant to comply with the DOE Order.

On June 1, 2006, Mirant entered into an Administrative Compliance Order (ACO) with EPA regarding operation of the Plant. (See Appendix B.) On June 2, 2006, DOE concluded that operation of the Plant under Option A did not provide an adequate level of electric reliability to the Central D.C. area and that operation of the Plant pursuant to the ACO was necessary to assure an adequate level of electric reliability to the Central D.C. area. Mirant has since that time operated the Plant in accord with those instructions from DOE. Since June 2, 2006, the operation of the Plant under the Order thus followed the scheme summarized in the following paragraphs. (See Section 4.1 for details.) The ACO will expire one year after it was issued, on June 1, 2007.

During “non-line outage situations” the operation of the Plant must follow the ACO, under which Mirant is to “keep as many units in operation,” and “take all other measures to reduce start-up time of units not in operation, for the purpose of providing electricity reliability so long as such operations are in accordance with paragraph B of Part IV of the ACO.” Among other things, paragraph B authorizes operation in accordance with “daily predictive modeling.” Under daily predictive modeling, the Plant operators acquire the appropriate weather forecast for the next day and use that forecast, along with their planned operating parameters, as inputs to conduct a computer modeling run for the following day’s planned operation. If the modeling results indicate that operating the Plant under those conditions would not cause a modeled NAAQS exceedance for 3-hr and 24-hr average SO₂ and PM₁₀, the operators may run the Plant on that day using those parameters. If the modeling results indicate that operation of the Plant would cause an exceedance of these NAAQS, the operators adjust their planned operating parameters until the modeling results indicate compliance with the NAAQS. The operators may then operate the Plant using those parameters. Thus, under this scenario the Plant can operate on any one day up to the maximum level allowed by the preceding day’s weather forecast.

The ACO requires Mirant to maintain alarms that alert the Plant operators if monitored average concentrations reach 80% of the standards for SO₂, including the annual SO₂ standard. In addition, the ACO requires Mirant to install and operate six new SO₂ ambient monitoring stations in the vicinity where elevated pollutant concentrations have been predicted and to conduct actual monitoring of ambient SO₂ concentrations.

During “line outage situations,” the ACO places environmental requirements on Mirant in addition to the requirements of the DOE Order. It requires Mirant to “take all reasonable steps to limit the emissions of PM₁₀, NO_x and SO₂ from each boiler, including operating only the number of units required to meet PJM’s directive and optimizing its use of trona injection to

minimize SO₂ emissions.” Further, the ACO requires that Mirant achieve “80% reduction of SO₂ emissions unless: 1) Mirant demonstrates ... that 80% reduction is not necessary to achieve compliance with the NAAQS; or 2) Mirant demonstrates that 80% reduction is not logistically feasible because of such factors as the quantity of available trona and the predicted duration of the outage.” If Mirant demonstrates that 80% removal is not logistically feasible, it is required to submit a plan to EPA for optimizing its use of trona.

On September 28, 2006, DOE issued an extension of the Order, including all of its terms and conditions, until 12:01 am on December 1, 2006.

Table 1.3-1. Chronology of major actions and events related to the Plant

Date	Agencies and other companies	Mirant; Potomac River Generating Station
2004		
September 23	Effective date of Order by Consent between VDEQ and Mirant	
2005		
until August 20		Historical operations; <i>Pre-shutdown mode for this SEA</i>
August 19		Mirant submitted emissions modeling study to VDEQ
August 19	VDEQ requested Mirant to immediately undertake actions to protect human health and environment around the Plant	
August 21		Output at Plant reduced to lowest feasible level from all five units
August 24		Operations at the Plant ceased
August 24	D.C. Public Service Commission filed emergency petition and complaint with DOE and FERC	
September 21		Unit 1 (one of the two load-following or cycling units) restarted on an 8-8-8 basis ³
September 21 - November 11		Unit 1 operated on an 8-8-8 basis

³ That is, in any given 24-hour period, the unit ran for up to eight hours at power levels up to its maximum level of 88 MW, ran for eight hours at its minimum level of 35 MW, and did not run for eight hours.

Table 1.3-1. Chronology of major actions and events related to the Plant

Date	Agencies and other companies	Mirant; Potomac River Generating Station
November 11 - November 23		Unit 1 operated on an 8-8-8 basis with trona testing
November 24 - December 14		Unit 1 operated on an 8-8-8 basis with Colombian coal testing, but without trona
December 15 - December 20		Unit 1 operated on an 8-8-8 basis with Colombian coal and trona testing; <i>Pre-Order mode for this SEA</i>
December 20	DOE consulted with CEQ	
December 20	The Secretary of Energy issued emergency order requiring Mirant to operate the Plant to assure a reliable supply of electricity to central Washington, D.C.	
December 21- December 23		Plant operated as during December 15 - December 20 period
December 22	DOE consulted with CEQ	
December 24		No data available on Plant operations
December 25 - December 31		Unit 1 operated without using low sulfur coal or trona
December 30		Mirant submitted its compliance plan (also known as the Operating Plan) to DOE identifying two options, A and B
2006		
January 1		No data available on Plant operations
January 2 -3		Unit 1 operated without using low sulfur coal or trona
January 4	DOE instructed Mirant to implement proposed Option A in compliance plan	Plant began to operate under conditions in Option A in compliance plan; Plant continued to operate under Option A until June 2 except during transmission line outages (indicated below).

Table 1.3-1. Chronology of major actions and events related to the Plant

Date	Agencies and other companies	Mirant; Potomac River Generating Station
January 6	PJM specified that it was necessary for Mirant to operate the Plant to meet entire Central D.C. load during transmission line outages Pepco proposed for January 7 - 19 and 22 - 27 for maintenance.	
January 7 - 19		Plant operated to meet entire Central D.C. load during line maintenance.
January 13	DOE consulted with CEQ	
January 17	DOE consulted with CEQ	
January 20	DOE issued <i>Federal Register</i> notice describing its emergency action and requesting comments on scope of the SEA.	
January 21		A second trona unit became operational
January 21 - 28		Plant operated to meet entire Central D.C. load during line maintenance.
February 21	End of comment period on <i>Federal Register</i> notice	
March 6	Pepco receives permission from the D.C. Public Service Commission to construct two new 230-kV lines into the D.C. area and two new 69-kV lines to serve the Blue Plains Wastewater Treatment Plant	
March 20		Third trona unit became operational
March	U.S. Department of Health's Agency for Toxic Substances and Disease Registry began a review of the existing air quality and other environmental data related to the Plant, as requested by the Director of the Alexandria Health Department.	
May 31		All five trona units operational
June 1	EPA issued an ACO to Mirant	
June 2	DOE instructed Mirant to comply with the ACO with EPA	

Table 1.3-1. Chronology of major actions and events related to the Plant

Date	Agencies and other companies	Mirant; Potomac River Generating Station
June 20		Operation began in accordance with daily predictive modeling
July 15	Pepco places two newly constructed 69-kV lines into service at the Blue Plains Wastewater Treatment Plant	
September 28	The Secretary of Energy extended emergency order for two months	
October 1	DOE Order was scheduled to expire at 12:01 am	
November 27 - December 11	Pepco plans transmission line outage for repairs	Full Plant generation will be required to meet central D.C. predicted load because of Pepco line repairs.
December 1	Extension to DOE Order expires at 12:01 am	
2007		
February 19 - March 5	Pepco plans transmission line outage for upgrades	Full Plant generation will be required to meet Central D.C. predicted load because of Pepco line upgrades.
May 2 - 15	Pepco plans transmission line outage for upgrades	Full Plant generation will be required to meet Central D.C. predicted load because of Pepco line upgrades.
May 21 - June 15	Pepco plans transmission line outage for upgrades	Full Plant generation will be required to meet Central D.C. predicted load because of Pepco line upgrades.
June 1	The ACO expires.	
late June	Pepco plans to have two new 230-kV transmission lines in service	.
Fall		Mirant plans to take units out of service to reconfigure the exhaust stacks.

1.4 National Environmental Policy Act (NEPA) Process

Major Federal actions significantly affecting the human environment generally call for DOE to prepare an environmental impact statement (EIS) before taking the action to analyze

impacts in compliance with NEPA. However, in emergency situations, pursuant to 40 CFR 1506.11, the CEQ's NEPA regulations provide that agencies consult with CEQ to determine what alternative arrangements the agency will take in lieu of preparing an EIS. DOE consulted with CEQ on December 20, 2005, December 22, 2005, January 13, 2006, and January 17, 2006, on a plan for alternative NEPA arrangements. Under this plan (71 FR 3279, January 20, 2006) DOE agreed to:

- Prepare a SEA to examine the potential impacts resulting from issuance of the Order and describe further DOE decision-making regarding reasonable future alternatives;
- Provide opportunities for public involvement;
- Continue to consult with EPA and the VDEQ concerning information on emissions, modeling results, potential mitigation measures, and any changes in the operation of the Plant; and
- Identify in the SEA steps that could be taken to mitigate any impacts from the DOE Order.

Consistent with the consultations with CEQ, DOE has prepared this SEA.

1.5 Public Involvement

As described above, on January 20, 2006, DOE published a *Federal Register* notice (71 FR 3279) (Appendix C) in which DOE described the action it had taken under the Order and reported its discussions with CEQ and its agreement to issue an SEA as part of its alternative arrangements for NEPA compliance.

DOE also used that *Federal Register* notice to request public comments on the information in the notice, as well as on issues to be addressed in the SEA. The comment period closed on February 21, 2006. DOE received comments from the following organizations: the Mount Vernon group and the Virginia Chapter of the Sierra Club; the Southern Environmental Law Center on behalf of itself and the American Lung Association of Virginia ; the City of Alexandria; and the Institute for Public Representation on behalf of the Potomac Riverkeeper, Inc., the Patuxent Riverkeeper, and the Anacostia Riverkeeper at Earth Conservation Corps. These comments are posted on the DOE website described below. Commentors identified many of the same issues that DOE had determined should be covered in the SEA. Section 1.6 describes where these issues are addressed in this document.

DOE maintains a website containing information (under DOE Docket EO-05-01) about the D.C. Public Service Commission Petition, its proceedings, and the DOE Order itself: <http://www.oe.energy.gov/permitting/372.htm>. This website also provides links to correspondence related to the petition and the Order, as well as the *Federal Register* notice and the comments received on that notice.

1.6 Scope of the Analysis

Based on its own evaluation of potential impacts and the concerns expressed by commentors, DOE has analyzed the below effects of Plant operations under the Order in the indicated sections of this SEA. Cumulative effects are discussed as appropriate in each section as described at the beginning of Section 4.3.

- Effects of any increased *air emissions* (Section 4.3.1);
- *Health* effects on Plant workers and the public of any increased air pollution; commentors on the DOE *Federal Register* notice expressed particular concern about impacts of increased particulate emissions, especially particulate matter smaller than 2.5 microns (PM_{2.5}), and of increased emissions of trace metals and hazardous air pollutants (especially arsenic, beryllium, lead, chromium, cadmium, nickel, and mercury) (Section 4.3.2);
- *Water quality* (Section 4.3.3) and *ecological* (Section 4.3.4) effects due to changes in Plant water use and releases or any increased deposition of air pollutants on soil and terrestrial communities, water bodies, and watersheds; commentors on the DOE *Federal Register* notice expressed concern about the potential for any increased emissions of SO₂ and NO_x to contribute to acid rain, nutrient loading to aquatic systems, and deposition of heavy metals, and the subsequent impacts on the aquatic resources of the Chesapeake Bay and several of its tributaries, specifically the Potomac, Anacostia, and Patuxent rivers;
- *Waste management* impacts (Section 4.3.5), particularly impacts of trona utilization, which commentors on the DOE *Federal Register* notice identified as a concern;
- *Transportation impacts* from increased shipping of coal and trona to the Plant and of wastes away from the Plant (Section 4.3.6); and
- *Environmental justice* impacts (Section 4.3.7).

This SEA also describes alternatives for potential future decision-making that include mitigation measures should the Order be further extended. Among these are several measures suggested by commentors on DOE's *Federal Register* notice on the proposal to prepare this SEA and parties commenting on the Order itself.

Because of the limited nature of the action, certain types of impacts that are usually analyzed in NEPA documents are not addressed.

- Because there would be no construction outside the footprint of the existing facility, no impacts to *land use, soil structure, floodplains, or aesthetics* are expected.
- Because only very small amounts of construction and employment are associated with the changed operations at the Plant, no appreciable effects on *social or economic resources* are anticipated.

A commentor expressed concern about possible adverse effects of trona utilization on Plant equipment. This concern is not addressed because it is not considered to be an environmental impact.

2. DESCRIPTION OF THE MIRANT POTOMAC RIVER GENERATING STATION

The Plant, which has been operating since 1949, was acquired by Mirant Potomac, Inc in 2000. It is located in Alexandria, Virginia, on the western bank of the Potomac River near the District of Columbia, about 5 miles (8 km) south-southwest of the U.S. Capitol building. (See Figure 2-1.) It is almost directly across the river from the Blue Plains Wastewater Treatment Plant and near Ronald Reagan Washington National Airport. Two National Park Service sites, the George Washington Memorial Parkway, developed both as a memorial to George Washington and to preserve the natural scenery along the Potomac River (NPS undated), and the Mount Vernon Trail (Figure 3.4-1), run past the Mirant Plant.

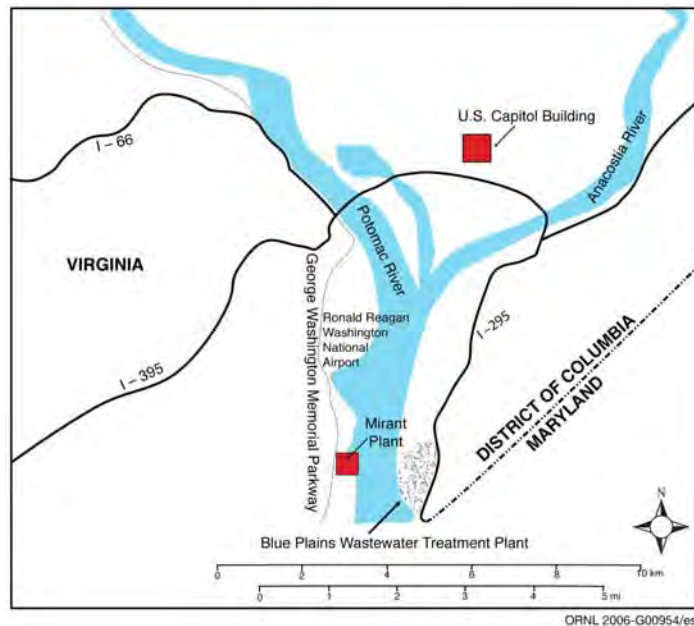


Figure 2-1. The location of the Plant in relation to the central Washington, D.C. area.

The site occupies approximately 28 acres (11 ha) and was relatively remote when the power plant was built. Alexandria has, however, grown up around it, and residential areas are now located immediately adjacent to the Plant. (See Figure 2-2.)

2.1 Site Layout

The footprint of the Mirant Plant is typical for a coal-fired electricity generation facility (see Figure 2.1-1), consisting of a large coal pile and a set of five steam generating boilers. The Plant has five stacks, each 161 ft (49 m) high (Mirant 2006a).

2.2 Plant Equipment and General Operation

The Plant consists of five steam boilers and associated generators with a net generating capacity of 482 megawatts (MW) of electricity for delivery to Central D.C. area customers. Units 1 and 2 are designed to be capable of load-following or cycling; that is, they are capable of changing power levels quickly as demand rises or falls. These units each have a generating capacity of 88 MW (with an operating range of 35 MW to 88 MW). Units 3, 4, and 5 are

designed for baseload operation; that is, they are intended to generate power at a steady rate for extended periods, typically 24 hours per day, and have historically been used more than Units 1 and 2 (Mirant 2006a). Units 3, 4, and 5 each have a generating capacity of 102 MW (with an operating range of 35 MW to 102 MW).

The facility uses oil to pre-heat units during startup and then burns coal. The Plant receives coal by rail car delivered by the CSX Railroad. (See Figure 2.1-1.) The rail cars are unloaded at a dedicated rail siding at the Plant. Typical plant operations involve unloading the rail cars and feeding some coal directly into the boiler building; additional coal is stored on-site in an outdoor coal pile with a capacity of 135,000 tons (122,000 metric tons). The coal storage yard occupies 4 acres (2 ha) and has an average coal-pile height of about 30 ft (9 m). Diesel-fueled bulldozers move the coal around the footprint of the coal pile, and a conveyor system transfers coal from the coal pile into the boiler building. The coal is pulverized in the boiler building and sized for injection into the five boilers. Steam is then piped from the boilers into the turbine building where the generators produce electricity.

Flue gases from each of the five boiler units exhaust to the atmosphere through separate, dedicated stacks. (See Figure 2.1-1.) Pollution abatement equipment at the Plant consists of hot- and cold-side electrostatic precipitators for each boiler unit. These precipitators remove solid particulate matter, called fly ash, from the exhaust gas streams. The fly ash collected by the precipitators is stored in a pair of on-site silos prior to being shipped by covered truck for off-site

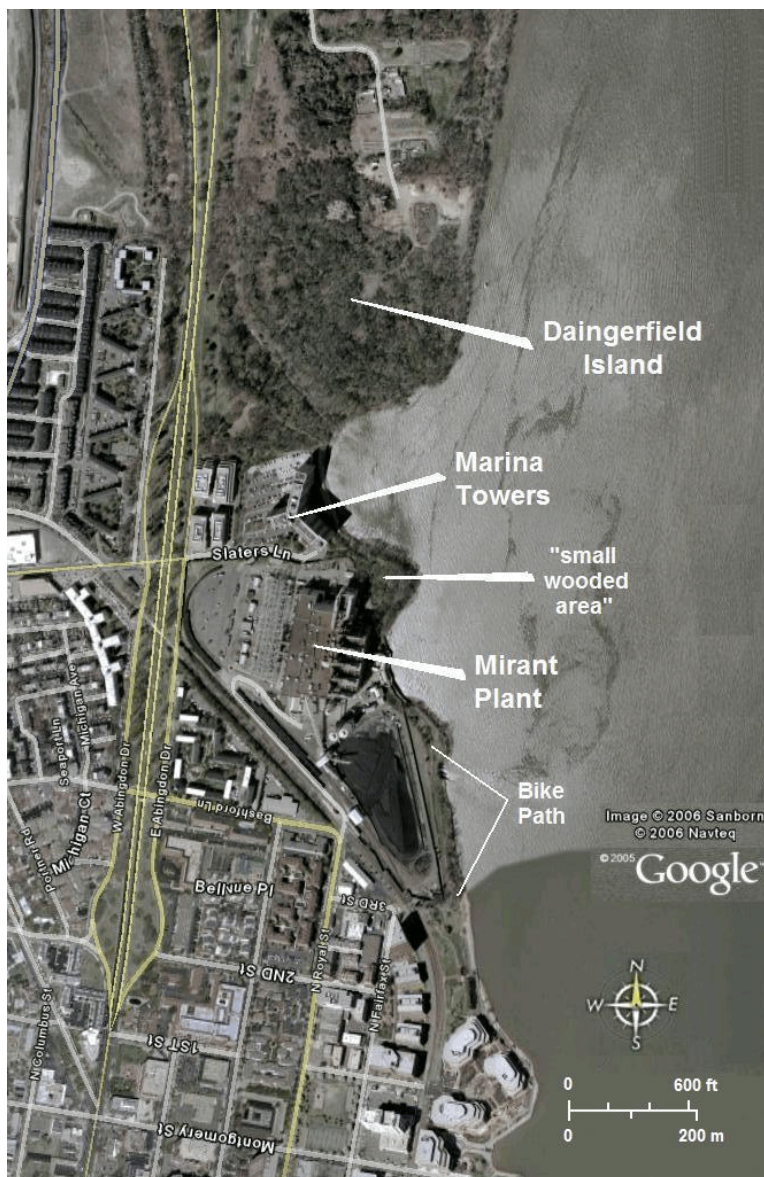


Figure 2-2. Aerial photo showing the Plant and surrounding residences.

disposal. Bottom ash from the boilers is collected and stored in a silo prior to being shipped off-site for beneficial use. (See Section 2.4.3)

The Plant also has trona injection units for each of the five boiler units. Each trona injection unit consists of 8 or 10 injection nozzles in the outlet duct from the boiler economizer to the hot-side precipitator inlet. Each injection unit is capable of injecting trona at a rate of up to 12,000 lb/hour (5,500 kg/hour), which Mirant's study determined to be sufficient to remove 80% of SO₂ from flue gas (Mirant 2006c). At maximum capacity the trona injection units on all five boilers can utilize a total of 25 tons (23 metric tons) of trona per hour to remove about 80% of SO₂ from flue gases.

Trona is delivered to the site in 100-ton (91-metric ton) railcars shipped directly from the mine in Green River, Wyoming. Trona is fluidized and transferred pneumatically from the railcars to a 35-ton-capacity (32-metric ton-capacity) trona feed trailer adjacent to each boiler. Trona is transferred pneumatically to the boiler unit outlet duct where it is injected.

The Plant has a once-through cooling water system. Raw water is pumped from the Potomac River through a 1,250-ft² (116-m²) rectangular intake area located on the river bottom along the shoreline, about 10 ft (3 m) below the water surface (Personal communications between D. Cramer, Mirant Corporation, and E.D. Smith, Oak Ridge National Laboratory, July 12, 2006, and between A. Wearmouth, Mirant Corporation, and E.D. Smith, Oak Ridge National Laboratory, July 21, 2006). The intake area is made up of 10 intake bays (two for each of the boiler units), each of which is 13.5 ft (4.1 m) long by 9 ft (3 m) wide and equipped with a 30,000-gal/min (about 100 m³/min) pump (Personal communication between A. Wearmouth, Mirant Corporation, and E.D. Smith, Oak Ridge National Laboratory, July 21, 2006). Mirant installed new fine-mesh screens on the intakes in July and August 2005. One screen on an intake for Unit 1 is fitted with "fish buckets" for enhanced fish protection. All screens, with or without the enhanced system of fish recovery, facilitate the return of fish to the river south of the power plant intake. After removing debris and suspended solids, the Plant uses this water to cool condensers and auxiliary equipment associated with steam turbines (Mirant 2006b). Major water

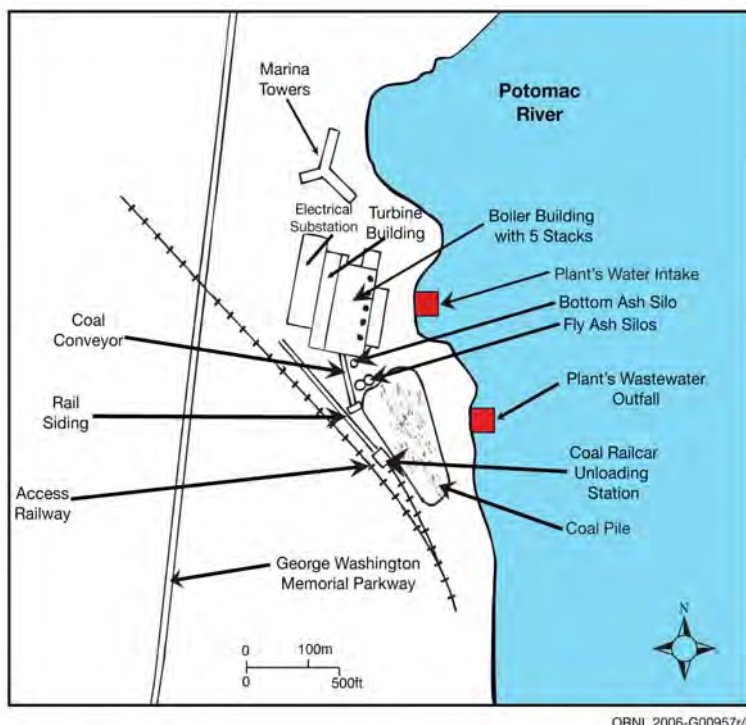


Figure 2.1-1. The site layout of Mirant's Potomac River Generating Station.

treatment equipment includes a clarifier, settling pond, neutralization system, and an oil/water separator.

2.3 Resource Requirements

The Plant primarily uses three resources: coal, trona, and water. Each of these is discussed separately in this section.

In the period prior to August 24, 2005, the Plant typically used an average of about 2,280 tons (2,050 metric tons) of coal per day. Operation at full capacity could require up to 5,150 tons (4,670 metric tons) of coal daily. The Plant normally used central Appalachian coal with a heating value of about 12,000 Btu/lb, an ash content of about 14%, a sulfur content of 0.64% by weight, and a carbon content about 67% by weight.

Analyses of coal burned in 2003 indicates that the average mercury content was between 0.03 and 0.07 ppm (dry). DOE conservatively assumes that the coal consumed by Mirant contains 0.07 ppm mercury on average, or about 1.4 lb (0.6 kg) mercury per 1,000 tons (910 metric tons) of coal.

The coal data that Mirant provided to DOE did not include concentrations of toxic metals other than mercury. Table 2.3-1 presents some published data on concentrations of seven trace metals in other central Appalachian coals. These analyses provide an approximate indication of levels that may be present in the central Appalachian coal burned by the Plant.

Table 2.3-1. Ranges of values for trace metal concentrations in as-mined samples of Appalachian coals

Trace metal	Reported concentrations (mg/kg)
Arsenic	7 – 23
Cadmium	ND – 0.2
Lead	15 – 24
Selenium	ND – 2.9
Beryllium	1 – 2
Chromium	30 – 63
Nickel	18 – 34

ND = below quantitation limit
Source: Palmer et al. 1997.

Trona consumption is determined by the target for SO₂ removal. Theoretical calculations show that if trona reacted completely with SO₂ in the hot-side precipitator inlet gas, 2.354 parts by weight of trona would be required to react with each part by weight of SO₂ (e.g., 2.345 lb trona per lb of SO₂). However, testing by Mirant found that much larger quantities of trona must be used in order to achieve desired SO₂ removal rates. Addition of trona to the exhaust gas stream at five times the theoretically calculated rate was found to remove 80% of the SO₂ (Mirant 2006c). For typical coal burned at the Plant, removal of 80% of SO₂ would require 0.15 lb of trona per lb of coal burned (1 lb trona per 6.7 lb coal). Because Mirant does not operate the Plant to achieve 80% SO₂ removal most of the time, average trona consumption is about 1 lb for every 8.5 lb of coal consumed (Personal communication between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006).

Water withdrawals from the Potomac River for cooling water and other in-plant uses are estimated to be about 1% higher than discharges (Personal communication between A. Wearmouth and D. Cramer, Mirant Corporation, and E.D. Smith, Oak Ridge National Laboratory, July 14, 2006). Therefore, based on discharges (Section 2.4.2), withdrawals are estimated to have averaged somewhat less than 350 million gal/day (1.3 million m³/day) under pre-shutdown operating conditions (prior to August 24, 2005).

2.4 Waste and Effluents

2.4.1 Air Emissions

The VDEQ approved a Stationary Source Permit to Operate on September 18, 2000, and a Phase II Acid Rain Permit on February 28, 2003. The Stationary Source Permit limits NO_x (as NO₂) emissions to 0.38 lb/MBtu. The EPA judicial consent decree, as amended (EPA 2004, 2006g), requires Mirant to limit Plant total NO_x emissions during the May 1 to September 30 period each year to 1,600 tons (1,500 metric tons) through 2009, among other things. The Acid Rain Permit allocates annual allowances for air emissions of SO₂ during its effective period of January 1, 2003, through December 31, 2007. SO₂ allowances for individual generating units range from 2308 to 3036 tons/year and total 13,344 tons/year for all units combined; in addition, the permit authorizes Mirant to acquire SO₂ allowances from other sources. The Acid Rain permit also limits emissions of NO_x, but the limitation on NO_x is less restrictive than the limit in the Stationary Source Permit.

The coal burned at the Plant averages about 67% by weight carbon. On a day when the Plant consumed 2,280 tons (2,050 metric tons) of coal, as it typically did in the period prior to August 24, 2005, it released about 11 million lb (5,600 tons) of CO₂.

2.4.2 Water Effluents

Plant effluents, including cooling water, boiler blowdown, runoff from the coal pile and fly ash handling areas, and other storm water runoff, are discharged to the Potomac River under National Pollutant Discharge Elimination System (NPDES) permit DC0022004. This permit was last issued for a 5-year duration in 2000 and expired in 2005. Mirant applied for renewal in 2004 (Wearmouth 2004), and the existing permit remains in force while EPA considers the application for renewal (Capacasa 2005). According to the renewal application (Wearmouth 2004), under historical operating conditions discharge under this permit averaged almost 345 million gal/day (1.3 million m³/day), of which all but about 0.4 million gal/day (1,500 m³/day) was once-through cooling water.

Boiler blowdown and effluent from treatment (i.e., demineralization) of intake water are treated by sedimentation and neutralization. Before being mixed with other wastewaters, they are monitored (in accordance with permit requirements) for flow rate, pH, total suspended solids, and oil and grease to verify that concentration limits in the permit are met. Ash clarifier system wastewater and runoff from the coal pile and fly ash handling areas are treated by rapid mixing, flocculation, and precipitation. They are monitored for the same set of parameters prior to mixing with other wastewaters. Once-through cooling water and storm water runoff from uncontaminated areas are blended with the treated effluents and discharged without additional treatment. No chlorine or other chemicals are added to the cooling water or used in the Plant's other water processes.

The NPDES permit requires monitoring of flow rate and other parameters at several internal monitoring points and at outfalls. Mirant submits monthly reports with the monitoring data to EPA and the Washington, D.C. Department of Health (Mirant 2006b). The Plant's primary wastewater outfall is subject to permit limits on pH, total residual chlorine, thermal output, and temperature rise in the river. Heat discharge in cooling water is limited to 4,286 MBtu/hr. Temperature rise in the river is limited to 2.8°C above ambient temperature and a maximum temperature of 32.2°C beyond a 1,000-ft (300-m) radius of the discharge point when the ambient river temperature is less than 27.8°C and beyond a 1,600-ft (490-m) radius when the river temperature is warmer than 27.8°C. Mirant conducted temperature surveys in the river in 2001 that confirmed that heat discharge from the Plant does not cause exceedance of these temperature limits, so temperature monitoring in the river is not required (Mirant 2002, NPDES permit document, and personal communication between A. Wearmouth, Mirant Corporation, and E.D. Smith, Oak Ridge National Laboratory, July 14, 2006).

Table 2.4-1 lists reported concentrations of selected contaminants in the Plant's cooling water intake and in effluent from the outfall that receives cooling water and treated wastewaters from demineralization, boiler blowdown, coal pile runoff, and fly ash handling. The table includes data for many parameters that are not listed in the Plant's NPDES permit. The near-neutral effluent has higher levels of biochemical oxygen demand, suspended solids, nitrate and nitrite, sulfate, aluminum, iron, manganese, copper, and fecal coliform bacteria than the intake

water, while loadings of chemical oxygen demand, total organic carbon, residual chlorine, phosphorus, and phenols are decreased in the effluent compared with the intake water.

Table 2.4-1. Water quality of Plant intake water and cooling water effluent

Contaminant	Intake Concentration (mg/L)	Effluent Concentration (mg/L, except as indicated)
Biochemical oxygen demand	9.6	14
Chemical oxygen demand	22	21
Total organic carbon	4.7	4.3
Total suspended solids	24	39
Fecal coliform bacteria	27	110
pH (pH units)	—	7.6
Chlorine, total residual	0.15	0.05
Fluoride	0.20	0.12
Nitrate-Nitrite as N	1.1	1.2
Nitrogen, total organic	ND	ND
Phosphorus	0.076	0.060
Sulfate	33	37
Aluminum	0.75	1.4
Iron	0.86	1.5
Manganese	0.11	0.13
Copper	ND	0.013
Zinc	0.023	0.023
Phenols, total	0.015	0.014

ND = Not detected

— = Not reported

Source: Wearmouth 2004; These values are from a single set of measurements and may not be representative.

2.4.3 Solid Wastes

The Plant's principal solid wastes are fly ash collected from exhaust gases and bottom ash from the boilers. (See Section 2.2.) Under pre-shutdown operating conditions prior to August 24, 2005, reported fly ash generation totaled about 14,200 tons/month (12,900 metric tons/month), equivalent to about 20% of coal consumption. Bottom ash generation equals about 25% of the fly ash generation (Personal communications between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006; and between D.

Cramer, Mirant Corporation, and E.D. Smith, Oak Ridge National Laboratory, July 12, 2006, and July 14, 2006).

Fly ash is sent by covered truck to the Brandywine Fly Ash Facility, a landfill located in southeastern Prince George's County, Maryland (Figure 2.4-1), that is owned and operated by Mirant Ash Management LLC and used solely for disposal of coal combustion ash. (See Section 3.5.) Plant fly ash is marketed for beneficial use, primarily for structural fill, but historically its utilization has been very limited (Personal communication between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006). The fly ash generated by the Plant under historical operating conditions is a pozzolanic material (that is, when mixed with water it “sets,” like cement), but its unburned carbon content is too high to permit its use as a cement substitute (TFHRC undated). Bottom ash from the Plant is used or sold for purposes such as road fill.

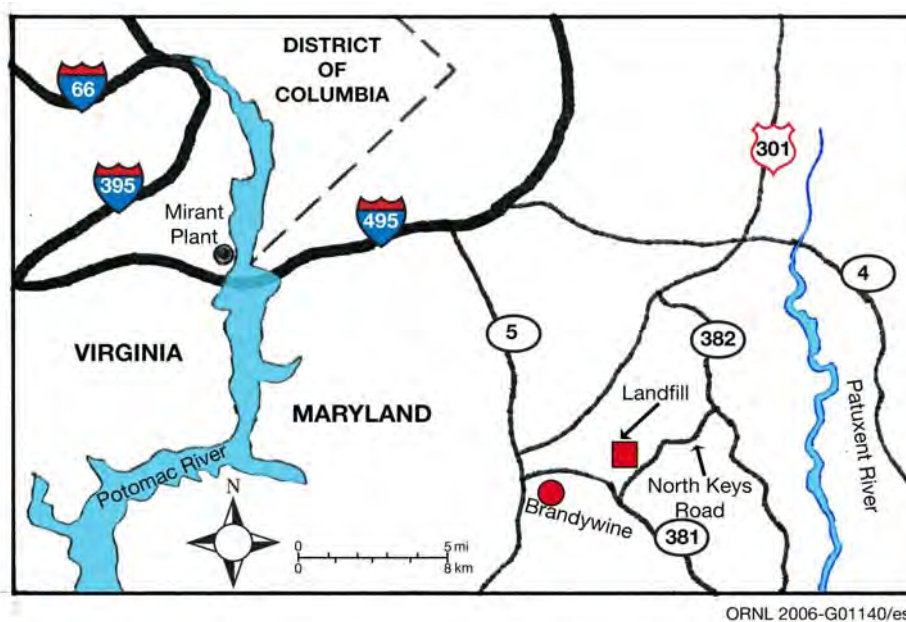


Figure 2.4-1. The location of and access routes to the Brandywine Fly Ash Facility used for disposal of solid wastes from the Plant.

Note: Mataponi Creek (not shown on the map) originates near Brandywine and flows east-northeast to the Patuxent River.

2.5 Changes to the Plant Since the DOE Order

Mirant has made several changes inside the existing Plant buildings since the DOE Order. The most important of these is the addition of trona injection units to all five boilers. Mirant has also made provision to withdraw trona from rail cars and transfer it to storage

containers inside the building. Several measures to control fugitive dust (for example, improved ash-loading systems for the two fly ash silos) were implemented during 2005 and 2006 in response to a 2004 EPA judicial consent decree (EPA 2004) that required Mirant to take actions to reduce fugitive particulate emissions. None of these changes included new construction or other disturbances at the Plant site.

Mirant is planning to merge the boiler exhaust gases from Units 1 and 2 and run the combined exhaust through the stack of Unit 1. Similarly Mirant is planning to merge the boiler exhaust gases from Units 3, 4, and 5 and run them through the stack of Unit 4. Mirant's modeling shows that combining the gas flows from the two units into one stack and from the three other units into another stack produces higher exit velocities and increases plume rise for all emissions into the atmosphere and, thus, lessens the potential for downwash impacts (Personal communication between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006).

Merging unit exhaust gases requires new common ductwork to be installed connecting the individual unit exhaust fan discharges, and installation of new higher capacity fans. This common ductwork will be connected to the existing stack at the existing location at the base of the stack. This common ductwork will be installed inside the existing plant structure and will not be visible from the ground since it will be located in-between the existing precipitator and stacks. There will be no foundations required for this ductwork.

Mirant plans to implement the exhaust system changes during the fall of 2007 (Personal communication between Richard Killian, EPA Region 3, and L.N. McCold, Oak Ridge National Laboratory, October 16, 2006). Each Plant generating unit is expected to have an outage of 7 to 9 weeks in order to remove the existing equipment and install the new equipment.

3. AFFECTED ENVIRONMENT

This section describes the resources and environmental conditions that could be affected by the DOE action. The areal extent of this “affected environment” is not the same for all potentially affected resource areas. Also, because the purpose of this descriptive information is to lay the foundation for evaluating potential environmental impacts of the action, not all resources and geographic areas are described at the same level of detail.

For air quality the extent of the affected environment is very large because air emissions from the Plant are transported within a large region. However, because the potential effects of greatest interest, including the potential for exceedances of ambient air quality standards, are concentrated in a local area very near the Plant, the description and assessment in this document focus primarily on a 36-mi² (93-km²) area within about 3 mi (5 km) of the Plant. Similarly, the area of primary interest for human health and environmental justice is this same 36-mi² (93-km²) area.

For water resources and ecosystems the affected environment consists primarily of the resources directly affected by Plant operations, including the Potomac River, the Plant site, and neighboring lands. However, because atmospheric deposition of contaminants emitted from the Plant to the air contributes to cumulative impacts to water quality and ecosystems in a larger region, the Anacostia River, Patuxent River, Chesapeake Bay, and other land and water areas (including Potomac River tributaries and their watersheds) within about 20 miles (32 km) of the Plant are treated as part of the affected environment for water resources and ecosystems.

For waste management and transportation the affected environment includes the Plant site; the landfill used for disposal of Plant fly ash; the local roads and rail facilities used for access to the Plant and landfill; and resources in the immediate vicinity of these facilities that may be affected by their air, water, or noise emissions.

3.1 Climate and Air Quality

3.1.1 Climate

The Plant is in Alexandria, Virginia, which lies at the western edge of the mid-Atlantic Coastal Plain, about 50 mi (80 km) east of the Blue Ridge Mountains and 35 mi (56 km) west of the Chesapeake Bay, adjacent to the Potomac River. Elevations range from a few feet (about a meter) above sea level to about 400 ft (122 m).

Weather observations in the vicinity have been kept continuously since November 1870. Since June 1941, the official observations have been taken at Ronald Reagan Washington National Airport (National Airport), just north of the Plant.

National Airport is located at the center of a large urban complex. As a result, low temperatures there are higher than those in surrounding areas. In winter low temperatures at the airport are often 10-15°F (6-8°C) higher than in suburban locations. There is less difference between airport and suburban high temperatures. The normal summertime high temperatures range from 85-90°F (30-32°C), and the average winter lows range from 26-32°F (-3 to 0°C). Normal precipitation is distributed rather uniformly throughout the year, ranging, approximately, from 2.7 to 3.9 inches (6.9 to 9.9 cm) per month.

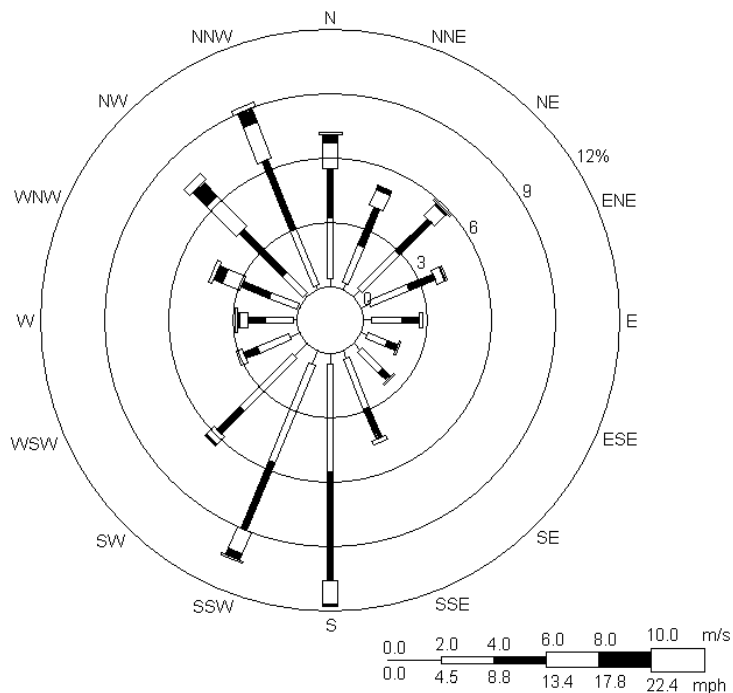


Figure 3.1-1. Wind rose for Ronald Reagan Washington National Airport, 2000-2004 weather data

Thunderstorms can occur at any time but are most frequent during the late spring and summer. The storms are often accompanied by downpours and gusty winds, but are not usually severe. Tornadoes, which occur infrequently, have resulted in significant damage. Severe hailstorms have occurred in the spring. Tropical storms can bring heavy rain, high winds, and flooding, but extensive damage from wind and tidal flooding is rare. Wind gusts of nearly 100 mi (160 km) per hour and rainfall over 7 inches (18 cm) have occurred during the passage of tropical storms.

Normal snowfall during the winter season is 15 inches (38 cm). The average date of the last freezing temperature in the spring is April 1, and the average date for the first freezing temperature in the fall is November 10.

Winds are most often from the south or south-southwest and from the north-northwest (Figure 3.1-1).

3.1.2 Air Quality

Criteria pollutants are defined as those for which National Ambient Air Quality Standards (NAAQS) exist (Table 3.1-1). These pollutants are carbon monoxide (CO), lead (Pb), nitrogen dioxide (NO₂), ozone (O₃), particulate matter less than or equal to 10 µm in aerodynamic diameter (designated PM₁₀), particulate matter less than or equal to 2.5 µm in aerodynamic diameter (designated PM_{2.5}), and sulfur dioxide (SO₂).

Table 3.1-1. National Ambient Air Quality Standards for criteria pollutants

Pollutant	Averaging period	Concentration
CO	8-hour ^a	9 ppm (10 mg/m ³)
	1-hour ^a	35 ppm (40 mg/m ³)
Lead	Maximum quarterly average	1.5 µg/m ³
NO ₂	Annual arithmetic mean	0.053 ppm (100 µg/m ³)
O ₃	4 th highest 8-hour daily maximum ^b	0.08 ppm (157 µg/m ³)
PM ₁₀	Annual arithmetic mean ^c	50 µg/m ³
	24-hour ^c	150 µg/m ³
PM _{2.5}	Annual arithmetic mean ^d	15 µg/m ³
	98 th percentile 24-hour ^d	65 µg/m ³
SO ₂	Annual arithmetic mean	80 µg/m ³ (0.03 ppm)
	24-hour ^a	365 µg/m ³ (0.14 ppm)
	3-hour ^a	1,300 µg/m ³ (0.50 ppm)

^a Not to be exceeded more than once per year.

^b The 8-hour standard is met when the 3-year average of the annual 4th highest daily maximum 8-hour O₃ concentration is less than or equal to 0.08 ppm.

^c The annual PM₁₀ standard is attained when the expected annual arithmetic mean concentration is less than or equal to 50 µg/m³ (3-year average); the 24-hour standard is attained when the expected number of days above 150 µg/m³ is less than or equal to 1 per year. EPA's October 17, 2006, rule making on NAAQS for particulate matter (EPA 2006j) revoked the annual PM₁₀ standard, effective December 18, 2006.

^d The annual PM_{2.5} standard is met when the annual average of the quarterly mean PM_{2.5} concentrations is less than or equal to 15 µg/m³, when averaged over 3 years. If spatial averaging is used, the annual averages from all monitors within the area may be averaged in the calculation of the 3-year mean. The 24-hour standard is met when the 98th percentile value, averaged over 3 years, is less than or equal to 65 µg/m³. Under new standards published on October 17, 2006, and effective December 18, 2006 (EPA 2006j), the 24-hour standard will be 35 µg/m³. The state of Virginia has until April 2008 to develop and submit to EPA for approval SIP provisions to implement, maintain, and enforce the new NAAQS for PM_{2.5}.

^e Same as primary standard.

Source: 40 CFR Part 50.

The NAAQS are expressed as concentrations of pollutants in the ambient air; that is, in the outdoor air to which the general public has access [40 CFR 50.1(e)]. Primary NAAQS define levels of air quality that EPA deems necessary, with an adequate margin of safety, to protect human health. Secondary NAAQS are similarly designated to protect human welfare by safeguarding environmental resources (e.g., soils, water, plants, animals) and manufactured materials. States may modify NAAQS to make them more stringent or set standards for additional pollutants. Virginia has adopted the NAAQS as the state standards without modifications.

Attainment status for NAAQS is determined primarily by evaluating data from ambient air quality monitoring stations. The monitoring station nearest to the Plant (AIRS 51-510-0009) is located at the Alexandria Health Department, 517 North Saint Asaph Street, 0.6 mile (0.9 km) south. The station monitors CO, SO₂, NO₂, and O₃. The nearest PM_{2.5} monitoring station (AIRS 51-013-0020) is located at Aurora Hills Visitors Center, 18th and Hays Streets, Arlington County, due west of Ronald Reagan Washington National Airport and 2.7 miles (4.4 km) north-northwest of the Plant. The nearest PM₁₀ monitoring station (AIRS 51-059-0018) is located at Mount Vernon Fire Station, 2675 Sherwood Hall Lane, Mount Vernon, 5.7 miles (9.2 km)

south-southwest of the Plant. Because no lead monitoring stations are employed in Virginia, this section does not discuss lead.

Table 3.1-2 summarizes recent air quality data in the vicinity of the Mirant Plant.⁴ The city of Alexandria and surrounding Arlington, Fairfax, Loudoun, and Prince William Counties are designated as NAAQS nonattainment areas for PM_{2.5} and the 8-hour O₃ standard (VDEQ 2006a, 2006b).

Table 3.1-2. Ambient air quality in the vicinity of the Plant, 2004

Pollutant	Regulated parameter	Monitored concentration ^a	NAAQS limit
CO ^b	Second highest hour	2.9 ppm	35 ppm (40 mg/m ³)
	Second highest 8-hour average	2.0 ppm	9 ppm (10 mg/m ³)
NO ₂ ^b	Annual average	0.024 ppm	0.053 ppm (100 µg/m ³)
O ₃ ^b	4 th highest 8-hour average	0.080 ppm	0.080 ppm (235 µg/m ³)
PM ₁₀ ^c	Annual arithmetic average	21 µg/m ³	50 µg/m ³
	Second highest 24-hour average ^e	44 µg/m ³	150 µg/m ³
PM _{2.5} ^d	Annual average	14.4 µg/m ³	15 µg/m ³
	98 th percentile 24-hour average	35.7 µg/m ³	65 µg/m ³
SO ₂ ^b	Annual average	0.006 ppm	0.03 ppm (80 µg/m ³)
	2 nd highest 24-hour average	0.021 ppm	0.14 ppm (365 µg/m ³)
	2 nd highest 3-hour average	0.054 ppm	0.50 ppm (1,300 µg/m ³)

^a Source: VDEQ 2005a (Just before publication of this document, Virginia released ambient air monitoring data for 2005 [VDEQ 2006c]. The updated background levels vary only slightly from the 2004 values reported and used here.)

^b Measured at Alexandria Health Department (AIRS 51-510-0009).

^c Measured at Mt. Vernon Fire Station (AIRS 51-059-0018).

^d Measured at Aurora Hills Visitors Center (AIRS 51-013-0020).

^e EPA's October 17, 2006, rule making on NAAQS for particulate matter (EPA 2006j) revoked the annual PM₁₀ standard, effective December 18, 2006.

Contaminants other than the criteria pollutants are present in the atmosphere in varying amounts that depend on the magnitude and characteristics of the sources, the distance from each source, and the residence time of each pollutant in the atmosphere. In the ambient air many of these pollutants are present in extremely small concentrations, requiring expensive state-of the art equipment for detection and measurement. Hazardous air pollutants are regulated at emission sources based on the National Emissions Standards for Hazardous Air Pollutants (40 CFR Parts 61 and 63); measurements of existing ambient air concentrations for many such pollutants are, at best, sporadic.

⁴ While additional air quality monitoring stations are located in Maryland and the District of Columbia, the monitoring station for each pollutant nearest the Plant is found in Virginia. (See Metropolitan Washington Council of Governments 2005 and VDEQ 2005a.)

3.2 Human Health

There is a well established association between exposure to outdoor air pollution and a broad variety of health effects, both acute and chronic. These health effects range from simple irritation such as burning eyes to premature death. The principal air pollutants generated by fossil fuel combustion that are associated with these health effects are PM, SO₂, and NO_x (WHO 2000). U.S. ambient air quality standards have been set at levels above background. For example, while the background concentration of SO₂ in the U.S. is about 1 µg/m³, the NAAQS for annual-average SO₂ concentration is 80 µg/m³. However, human health effects have been reported for concentrations below NAAQS levels for both PM and SO₂ (Dockery et al. 1993).

For the purposes of this SEA DOE has analyzed premature adult (age 30 and older) mortality as a useful indicator for health effects associated with air pollution because background mortality rates are readily obtainable, thereby strengthening the estimates, and the association between air pollution and mortality has well documented exposure response functions. The most recently available all-cause, all-age death rate for the area near the Plant is 7.5 deaths per year per 1000 population, as obtained from the Virginia Department of Health (2004). The most recent all-cause adult (age 30 and older) death rate in the region is 13 deaths per year per 1000 population.

3.3 Water Resources and Water Quality

Water resources potentially affected by Plant operations include the Potomac River and the Patuxent River, as well as the Chesapeake Bay, which is the destination for both of those rivers. The Potomac River supplies water to and receives effluent discharges from the Plant, and the watersheds of the Potomac and Patuxent Rivers include the land areas where air pollutants emitted from the Plant are most likely to be deposited. In addition, effluents from the landfill serving the Plant are discharged to Mataponi Creek, which is in the Patuxent River watershed. The Anacostia River and Rock Creek, which are tributaries to the Potomac located near the Plant, are also specifically discussed in this section.

3.3.1 Physical Setting and Hydrology

The Plant is situated in the Atlantic Coastal Plain physiographic province, in the watershed of Chesapeake Bay (Figures 3.3-1 and 3.3-2). Chesapeake Bay and its major tributaries, including the Potomac and Patuxent rivers, are “drowned river valleys.” That is, they are river valleys that were partially inundated by sea water when sea level rose following the end of the last Pleistocene glaciation. The Potomac, Patuxent, and other major streams in the region arise in upland areas and flow as fresh-water streams to the fall line near the edge of the

coastal plain. Below the fall line, the streams are considered to be estuaries, since their flow is modified by the influence of ocean tides. In the estuarine section of a stream, fresh water mixes with salt water in increasing proportions as the stream flows toward the sea. The effects of tides shelter the waters of these estuaries from the full effects of river currents, while river-valley geometry and stream flow shelter them from the full energy of ocean waves. Because they are sheltered from the flushing actions of both stream flow and ocean waves, water remains in these estuaries for a long time. Thus, pollutants discharged into an estuary remain there much longer than they would in an upland stream or in the open ocean. At the same time the sheltered waters of estuaries support exceptionally productive ecosystems. (See Section 3.4.)

3.3.1.1 Potomac River

The Plant is located next to the Potomac River, which flows from the Appalachian mountains to Chesapeake Bay, draining a 14,670-mi² (38,000-km²) watershed in Maryland, Virginia, West Virginia, Pennsylvania, and the District of Columbia

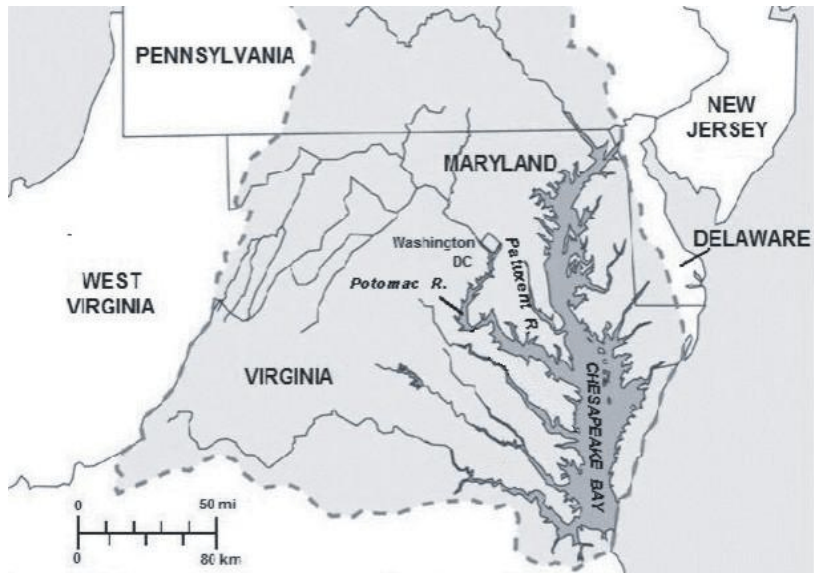


Figure 3.3-1. The Chesapeake Bay watershed includes the Patuxent and Potomac rivers.

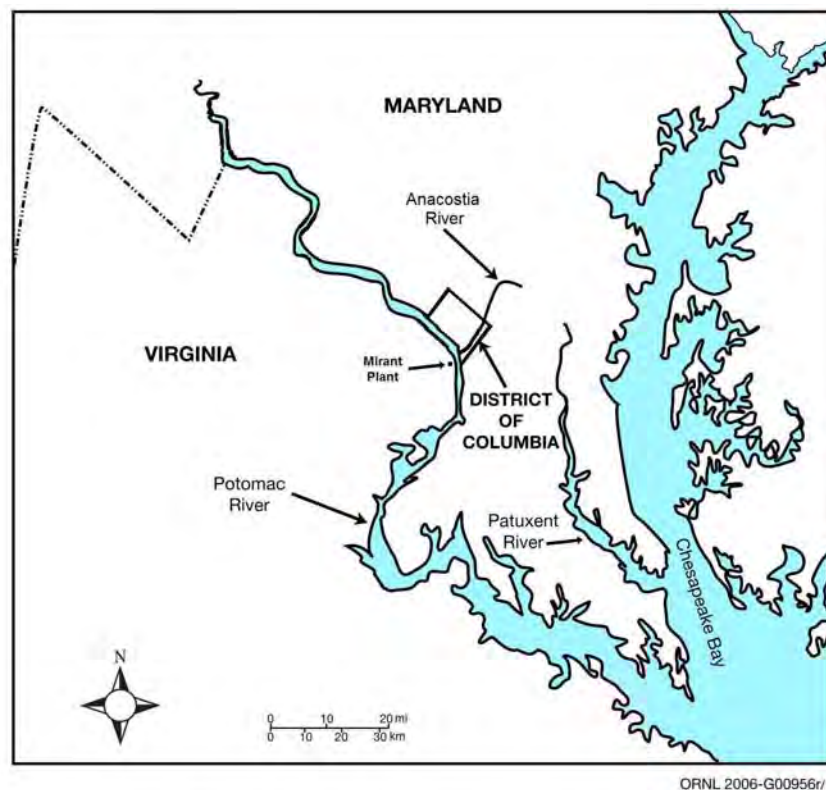


Figure 3.3-2. The Chesapeake Bay watershed near the Plant includes the Potomac, Patuxent, and Anacostia rivers.

(EPA 2000; Wilderness Society undated). The river is tidally influenced for about 110 miles (180 km) from the fall line at Little Falls, Maryland (located a short distance upstream from the District of Columbia border, about 11 miles [18 km] upstream from the Plant), to its mouth at Chesapeake Bay (EPA 2000).

While the entire tidally influenced reach of the river is an estuary, it is classified in three distinct hydrographic regimes: tidal river, transition zone, and mesohaline estuary. Adjacent to the Plant the Potomac is a tidal river with fresh water (salinity less than 500 mg/L) and a net seaward flow direction throughout the water column (EPA 2000). The transition zone begins approximately 38 miles (61 km) downstream from the fall line, about 27 miles (43 km) downstream from the Plant. The transition zone is about 22 miles (35 km) long and is characterized by variable salinity (from 500 to 10,000 mg/L) and significant mixing of fresh water with salt water from Chesapeake Bay. The lower 50 miles (80 km) of the river are classified as a mesohaline estuary with salinity varying from 5,000 to 18,000 mg/L (EPA 2000). Near the Plant the river channel has been extensively modified by past dredging and spoil disposal.

Average stream flow in the Potomac River at the fall line (above the zone of tidal influence) over the 50-year period 1931-1981 was 11,406 ft³/sec (7.4 billion gal/day or 28 million m³/day) (EPA 2000). Seasonally, flow is highest in the spring (February through May) and lowest in the late summer (July through September). September is the month with the lowest average flow, 4,126 ft³/sec (2.7 billion gal/day or 10 million m³/day). The long-term mean 7-day, 10-year low flow at the fall line is 628 ft³/sec (406 million gal/day or 1.54 million m³/day). The District of Columbia and some other area jurisdictions obtain public water supplies from the Potomac above the fall line.

3.3.1.2 Anacostia River

The Anacostia River is a tributary to the Potomac River that enters the Potomac approximately 4 miles (6 km) upstream from the Plant. The extensively urbanized Anacostia watershed encompasses 176 mi² (456 km²) in Montgomery and Prince George's County, Maryland, and the District of Columbia. The Anacostia is a tidal river for its lower 8.4 miles (13.5 km). Flow in the tidal reach is described as sluggish; this reach has an average water residence time of 30 to 35 days. Average flow into the tidal reach from free-flowing tributaries and reaches is approximately 138 ft³/sec (89 million gal/day or 338,000 m³/day) (Anacostia Watershed Network 2006).

3.3.1.3 Rock Creek

Rock Creek (Figure 3.3-3) is a tributary to the Potomac River that enters the river several miles upstream from the Plant. Approximately 80% of its watershed is in Montgomery County, Maryland, with the remainder in Washington, D.C. (MDOE 2006). The nontidal portions of the

creek occur mainly within Maryland and cover about 60 mi² (155 km²); the tidal portion is mainly within D.C.

3.3.1.4 Patuxent River

The Patuxent River watershed is immediately east of the Potomac River watershed in the Maryland counties of Anne Arundel, Calvert, Charles, Howard, Montgomery, Prince George's, and St. Mary's (Maryland DNR undated-a). The drainage divide between the Potomac and Patuxent watersheds is about 10 miles (16 km) east of the Plant. Only about 40% of the 849-mi² (220-km²) Patuxent River watershed contributes to the river's flow above the fall line; the remainder of the watershed drains directly to the river's estuary, which has a water surface area of about 49 mi² (127 km²) (Hagy and Kemp 2002).

Total stream flow to the Patuxent estuary averages about 728 ft³/sec (470 million gal/day or 1.78 million m³/day) (Boynton and Swaney 1998). Fresh water residence time in the estuary typically varies between 50 and 80 days (Hagy and Kemp 2002).

Mataponi Creek, the Patuxent River tributary that receives discharges from the Mirant landfill (Section 3.5), originates in the upland near Brandywine, Maryland (Figure 2.4.1) and flows east-northeast toward the Patuxent River, entering the fresh water tidal reach of the river at a location about 9 miles (14 km) northeast of Brandywine. No stream flow or water quality data have been located for Mataponi Creek.

3.3.1.5 Chesapeake Bay

The Chesapeake Bay is the largest estuary in the United States, about 200 miles (320 km) in length, with a surface area of about 4,400 mi² (11,000 km²) (including the estuarine reaches of its major tributaries) and a watershed of about 63,000 mi² (164,000 km²), including the District

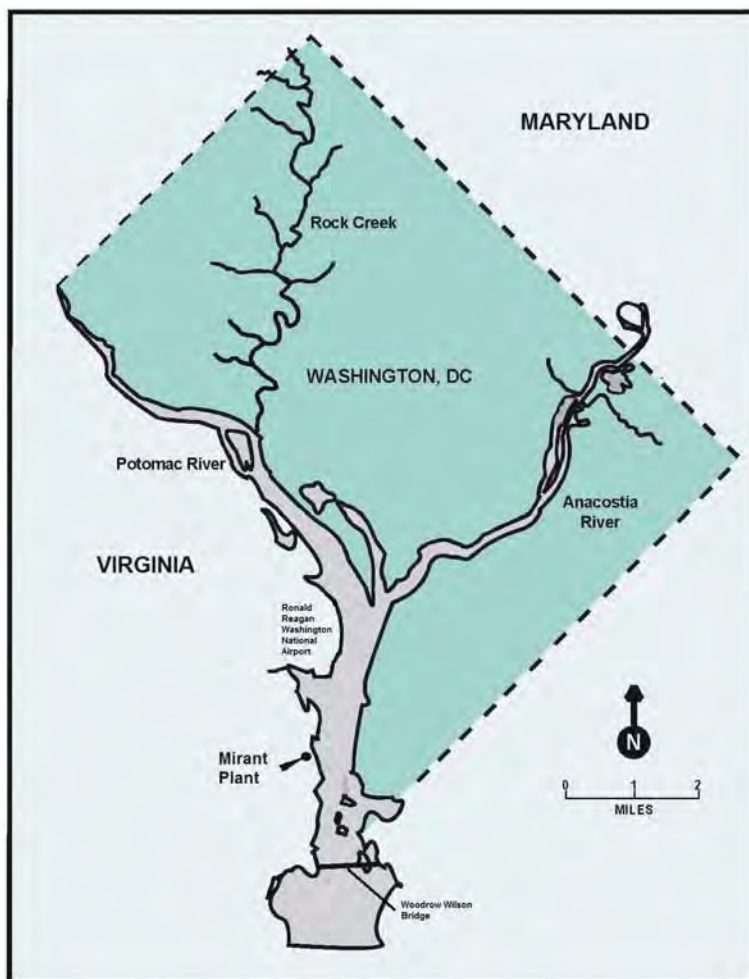


Figure 3.3-3. Location of features mentioned in the text.

of Columbia and parts of the states of Delaware, Maryland, New York, Pennsylvania, Virginia, and West Virginia (Figure 3.3-1). The Chesapeake Bay is the destination of all waters in the region. The Potomac and Patuxent rivers contribute about 15% and 1% of the stream flow into the Bay, respectively (Boynton and Swaney 1998). Average water depth in the Bay is about 22 ft (7 m).

3.3.2 Water Quality

Important water quality concerns for all potentially affected surface waters include the potential for excessive sedimentation and depletion of dissolved oxygen. Dissolved-oxygen depletion is attributable to excessive loadings of organic materials and nutrients. The long water residence times and poor flushing that are typical of estuaries increase the susceptibility of estuaries to pollution problems. Effects on aquatic ecosystems are the principal focus of concern regarding water quality in these waters, as discussed further in Section 3.4. Public water supplies are obtained from rivers and reservoirs above the fall line; tidal waters generally do not supply water for human consumption. Information about water quality conditions in specific surface water bodies is presented below.

3.3.2.1 Potomac River

Water quality in the tidally influenced sections of the Potomac River is controlled primarily by the mixing of fresh water from upland streams and salt water from Chesapeake Bay, resulting in variable salinity. In the vicinity of the Plant fresh water predominates over salt water, and total dissolved solids are less than 500 mg/L. Table 2.4-1 includes additional data on the quality of river water at the Plant's water intake.

Due to their volume, effluent discharges from the Plant and the Blue Plains Wastewater Treatment Plant have the potential to be important influences on Potomac River water quality near the Plant. Data on the quality of effluents from the Plant are provided in Table 2.4-1.

The Blue Plains Wastewater Treatment Plant, owned and operated by the District of Columbia Water and Sewer Authority, is directly across the Potomac River from the Plant. (See Figure 2-1.) This facility provides wastewater treatment services for the District of Columbia and portions of Montgomery and Prince George's Counties, Maryland, and Fairfax and Loudoun Counties, Virginia, with a combined population near 2.2 million. The Blue Plains treatment plant has a rated treatment capacity of 370 million gal/day (1.4 million m³/day) and a peak wet-weather capacity of 1.076 billion gal/day (4.1 million m³/day). Operation at the rated capacity delivers a water volume to the river equivalent to 5% of the average flow and more than 90% of the 7-day, 10-year low flow at the fall line. The Blue Plains facility is considered an advanced wastewater treatment facility, providing primary and secondary treatment followed by nitrification-denitrification, effluent filtration, chlorination-dechlorination, and post-treatment aeration (DC WASA 2006). Historically, wastewater effluents discharged at this site caused

severe water quality degradation in the Potomac estuary, including high bacteria levels and low levels of dissolved oxygen. Downstream water quality improved dramatically, however, following implementation of secondary and advanced treatment in the Blue Plains treatment plant (EPA 2000). The NPDES permit for the Blue Plains facility specifies stringent water quality limits for discharges, as indicated in Table 3.3-1.

Table 3.3-1. NPDES-permitted discharge limits for the Blue Plains Wastewater Treatment Plant

Contaminant		Maximum Concentration (mg/L, except as indicated)
Carbonaceous Biochemical Oxygen Demand		5.0
Total Suspended Solids		7.0
Phosphorus, total		0.18
Ammonia Nitrogen (NH ₃ -N)	May-October	1.0
	November-April	6.5
Dissolved Oxygen		5.0
Chlorine, total residual		0.02
pH (range of values, pH units)		6.0 to 8.5

Source: DC WASA 2006.

Principal water quality concerns for Potomac River tributary streams draining northern Virginia watersheds near the Plant include the effects of urbanization on aquatic habitats, high fecal coliform bacteria counts in some streams, and the need to protect the watersheds of water-supply reservoirs (Northern Virginia Regional Commission undated; Fairfax County Stormwater Planning Division 2001).

3.3.2.2 Anacostia River

Water quality conditions in the free-flowing tributaries of the Anacostia range from excellent to poor, but the tidal reach of the Anacostia River has very poor water quality. Principal water quality issues for the Anacostia watershed include sediment, trash and debris, toxic chemicals, combined sewer and stormwater overflows that discharge directly into the river, and other nonpoint-source pollution (Anacostia Watershed Network 2006). According to EPA (1997), urbanization has altered the Anacostia River and its tributary streams to the point that floods are ten times more frequent, summer flows are much lower, and stream water temperatures are 5 to 10° C higher than under natural conditions. Due to the long water residence time in the tidal reach of the river, this reach has been described as “a very efficient pollutant trap” (Galli et al. 2001). The tidal reach has chronically low dissolved oxygen levels that

threaten aquatic life and high bacterial levels that make it unsafe for swimming and other water contact activities.

Through a series of agreements, beginning in 1984, local, state, and Federal government agencies have committed to cooperative efforts aimed at restoring the river (Metropolitan Washington Council of Governments 1999). The parties have made progress in implementing measures that should improve water quality, including improving stormwater management, reducing combined sewer overflows and trash, changing land use management to protect sensitive headwater tributaries, and increasing riparian forest buffers; the current agreement calls for continued efforts (Anacostia Watershed Restoration Committee 2001).

3.3.2.3 Rock Creek

Because Rock Creek Park surrounds the entire length of Rock Creek in D.C. and Maryland parks surround most of its length upstream from the District, Rock Creek experiences fewer adverse water quality impacts from urbanization than does the Anacostia River. However, creek water quality is affected by sedimentation and other contaminants associated with urban stormwater runoff (EPA 1997).

3.3.2.4 Patuxent River

Upland streams in the Patuxent River watershed are well oxygenated (only 1% are reported to have dissolved oxygen levels below 5 mg/L), but stream bank instability and erosion reduce biotic habitat quality and contribute contamination to downstream areas (Maryland DNR undated-a). In the tidally influenced area of the main channel, salinity increases in the downstream direction, ranging from fresh to moderately saline. Nutrient loading is a water quality concern throughout the watershed, contributing to eutrophication and oxygen depletion in the lower estuary (Maryland DNR undated-c).

3.3.2.5 Chesapeake Bay

A principal focus of concern for Chesapeake Bay water quality is ecosystem health, which is threatened by excessive loading of nutrients (Section 3.4.2). The historic *Chesapeake Bay Agreement of 1983* established the Chesapeake Bay Program with the goal of restoring the Bay (CBP undated). Through this Agreement, which has been updated and revised several times, Pennsylvania, Maryland, Virginia, the District of Columbia, EPA, and the Chesapeake Bay Commission have committed to a coordinated set of goals and targets for restoration of the Bay ecosystem, including its water quality.

Excessive loading of nitrogen, a nutrient, has been identified as one major contributor to various ecological problems in Chesapeake Bay. (See Section 3.4.2.) Nitrogen occurs naturally in soil, animal waste, plant material, and the atmosphere. In addition to these natural sources,

sewage treatment plants, industries, vehicle exhaust, acid rain, and runoff from agricultural, residential, and urban areas contribute nitrogen to the Chesapeake Bay and its rivers. One of the specific goals set by the Chesapeake Bay Program to achieve the overall objectives of the Chesapeake Bay Agreement is to reduce annual nitrogen input to the Bay to no more than 175 million lb (79 million kg) by 2010. This value is 162 million lb (74 million kg) less than the estimated 1985 input of 337 million lb (153 million kg). Between 1985 and 2004 estimated total nitrogen input to the Bay was reduced by 67 million lb/yr (30 million kg/yr) (41% of the goal), with the biggest improvement coming from reductions in point-source loadings, such as from sewage treatment plants (CBP 2005). The majority of the future reductions in nitrogen loading to the Bay are expected to come from land-based measures such as reducing farm runoff into streams.

Another important source of nitrogen in the Bay is atmospheric deposition (both on land in the watershed and directly on water). Atmospheric sources are estimated to contribute about 91 million lb (41 million kg) of nitrogen to the Bay annually. In 1985 this represented 27% of the nitrogen entering the Bay; by 2000 the estimated fractional contribution from atmospheric deposition had increased to 32% due to reductions in inputs from other sources. About three-quarters of the atmospheric nitrogen that reaches the Bay is estimated to have been emitted in the form of NO_x (Blankenship 1997). In the seven-state region (i.e., Maryland, Virginia, Pennsylvania, New York, West Virginia, New Jersey, and Ohio) estimated to produce most of the air emissions that contribute nitrogen to the Bay, utilities are estimated to be responsible for 38% of the NO_x emissions, cars and trucks 35%, industries 6%, and other sources 21% (CBP 2000).

Much of the atmospheric nitrogen that is deposited on land within the Bay watershed is utilized in biological processes and retained in the ecosystem, so that it is not delivered to the Bay (CBP STAC 1996). Thus, delivery of atmospheric nitrogen to the Bay is estimated based on landscape characteristics, data from acid-deposition monitoring, and other data. Maps of estimated per-hectare delivery of nitrogen to the Bay from all parts of the watershed (Brakebill and Preston 2004) indicate that the total delivery of atmospheric nitrogen to the Bay (in all chemical forms) is about one-tenth to one-third of the atmospheric nitrogen estimated to be deposited to the land surface as NO_x.

Plans for achieving the 2010 nitrogen goal assume that input from atmospheric deposition will be reduced by 8 million lb/yr (3.6 million kg/yr) between 1985 and 2010 as a result of the implementation of new or proposed regulations aimed at achieving Clean Air Act mandates to reduce acid rain and ozone and to limit NO_x emissions from automobiles (Blankenship 1997, 2004). The Chesapeake Bay Program has not established any location-specific targets for reducing atmospheric nitrogen input, which can originate from sources outside the watershed as well as sources within the watershed.

3.3.2.6 Acid deposition

Acid deposition (often called acid rain), due to the dry or wet deposition of oxides of nitrogen and sulfur in the air, is a concern for water quality and ecosystems in the Appalachian mountains and northeastern United States. Acids derived from air emissions have the potential to dissolve, and thus mobilize, aluminum and other metals in soils and sediments, introducing toxic metals into surface waters.

Streams and lakes most susceptible to the impacts of acid deposition are those in watersheds where soils lack carbonate minerals and other alkaline constituents that can neutralize acids deposited from the atmosphere. Such watersheds are considered to be “poorly buffered.” In the state of Maryland approximately 96% of the 636 mi² (1,650 km²) portion of the Potomac River watershed surrounding the District of Columbia (including Maryland portions of the Anacostia watershed) and 98% of the Patuxent River watershed are classified as “well buffered” against acid rain (Maryland DNR undated-a and undated-b). Thus, in the watersheds most likely to receive atmospheric deposition of Plant emissions, surface waters are not particularly susceptible to adverse effects from acid deposition.

3.4 Ecological Resources

The Plant is located on the western bank of the Potomac River, in the Chesapeake Bay watershed (Figures 3.3-1 and 3.3-2). The region around it is a highly urbanized ecosystem that includes the District of Columbia. Development has transformed the ecological resources of the region, and they are greatly changed from early historical conditions (EPA 1997). The ecological condition has, however, improved from the highly degraded situation that was prevalent in the late 1950s and early 1960s, and the region continues to support terrestrial, aquatic, and wetland resources.

3.4.1 Terrestrial Resources

3.4.1.1 Vegetation

Since the turn of the 20th century, approximately 75% of the forest cover in the District of Columbia has been eliminated by human activities (EPA 1997). Regionally, tree cover declined more than 30% from 1972 to 1997 (American Forests 2002). In many places intentional plantings or invasions of exotic trees and other plants have displaced and substantially altered the native vegetation (EPA 1997). Agricultural and forest land cover are, however, still predominant in some parts of the region.

Daingerfield Island, which is administered by the National Park Service as part of the George Washington Memorial Parkway, lies about a quarter mile (less than a half kilometer) north of the Plant (Figure 3.4-1). No longer geographically an island, this flat 107-acre (43-ha), mostly wooded peninsula includes a large patch of forest on the eastern portion of the island with common suburban trees and understory plants (NPS 2002).

The National Park Service administers the land between the Potomac River and the Plant. This expanse includes a bike path that runs south from Daingerfield Island past the Plant and a small wooded area near the Plant at the edge of the Potomac River. (See Figure 2-2.) The vegetation in the small wooded area is similar to that on Daingerfield Island, common suburban tree and understory plant species.

3.4.1.2 Wildlife

Many of the animal species originally present in the D.C. region disappeared long ago (EPA 1997). Wildlife in the region is now dominated by opportunistic species characteristic of urbanized areas. Animals tolerant of human activities (e.g., opossums, raccoons, squirrels, black and Norway rats, house mice, stray cats and dogs) have increased in abundance due to the absence of larger predators and the abundant food offered by garbage. Bird species reflect a change from predominantly forest interior species to species representative of mixed land uses.

Wildlife on Daingerfield Island includes common urban species such as small mammals and birds (NPS 2002). Larger animals could possibly use the forest there for habitat. However, because the forest patch is separated from other forested areas by roadways, fields, and water bodies, the movement of large animals into the peninsular forest may be limited. The wooded

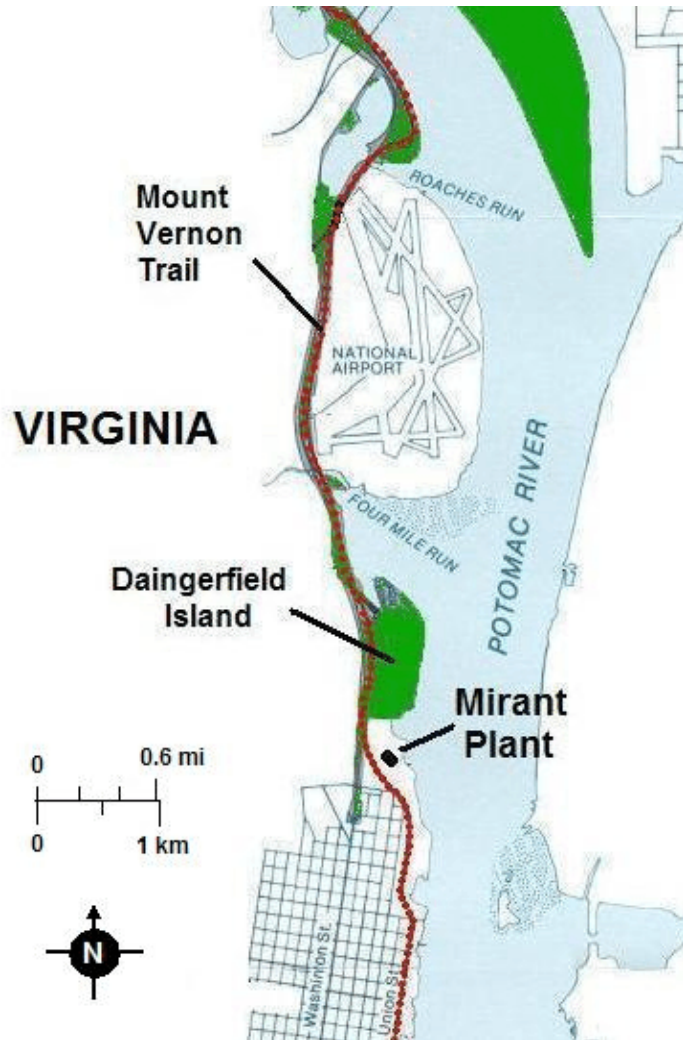


Figure 3.4-1. Location of National Park Service trail that passes the Plant.

area near the Plant is also too small and too isolated by roadways, fields, and water bodies to provide habitat that could be easily used by larger animals.

3.4.1.3 The Mirant Plant site

The 28-acre (11-ha) Plant site is almost entirely covered by facilities related to coal storage and electric power generation. However, it also includes a 1,500 ft² (140 m²) wildflower garden planted with woody and herbaceous vegetation for insects and pollinators.

Animals on the site include common urban wildlife species such as small mammals and birds. Artificial nesting structures for purple martins, eastern bluebirds, bats, and peregrine falcons are located within the small scattered areas of wildlife habitat.

3.4.2 Aquatic Resources

Aquatic ecosystems with the most potential to be affected by the Order include those in the Chesapeake Bay and some of its tributaries, particularly the Potomac, Anacostia, and Patuxent rivers and Rock Creek. (See Figures 3.3-2 and 3.3-3 and Section 3.3.) Coal-fired power plants can impact aquatic resources directly by the cooling water withdrawals and discharge of aqueous effluents and indirectly by the deposition of air pollutants (e.g., acid rain) into watersheds. The Plant withdraws cooling water from and discharges back to the Potomac River. The other rivers and the Chesapeake Bay are potentially affected indirectly by atmospheric deposition.

3.4.2.1 Potomac River

The estuarine portion of the Potomac River adjacent to the Plant supports aquatic communities that are recovering from past stresses. Historically the Potomac River supported dense stands of bay grasses along its entire length, but much of it was lost by the late 1930s (EPA 1997). A dense and wide patch of bay grasses has regrown and currently stretches from the Virginia Potomac shoreline at National Airport to the middle of the Potomac, extending past the southern tip and along the northern and eastern edges of Daingerfield Island that lies north of the Plant (NPS 2002). (See Figure 3.4-1.)

A large, tidally influenced river, the Potomac once possessed an exceptionally diverse and productive fish community, but species abundance and diversity are low compared to historic levels (EPA 1997). The Potomac River watershed supported large numbers of both resident, freshwater fish and anadromous fish (i.e., species that spend their adult lives in saltwater and spawn in freshwater), such as shad and river herring (*Alosa* sp.).

Even though the river has been degraded by the effects of human activities, a wide variety of fish species still occur in it. Many of these are exotic species (e.g., largemouth [*Micropterus salmoides*] and smallmouth bass [*Micropterus dolomieu*], walleye [*Sander*

vitreus]). Some native and exotic species present in the river (e.g., catfish [*Ictalurus punctatus*], crappie [*Pomoxis* sp.], sunfish [*Lepomis* sp.], largemouth and smallmouth bass, walleye) are important recreational species. The northern snakehead (*Channa argus*), a fish from Asia that has attracted public interest because it preys on other fish and can survive several days out of water, is believed to be established in the Potomac River and its tributaries (Fuller 2006). The estimated total fish abundance in the Potomac-Washington Metro Basin, which includes the Anacostia and Potomac rivers and a number of creeks, is 4.9 million fish (Maryland DNR undated-b).

An indication of the particular fish species that are affected by the Plant's cooling water withdrawals can be obtained from entrainment and impingement studies. Studies of aquatic organisms impinged (trapped) on the intake screens at the Plant during 2003-2004 provided information on the species that occur in that stretch of the Potomac (Personal communications between A. Wearmouth, Mirant Corporation, and M.S. Salk, Oak Ridge National Laboratory, July 24, and August 18, 2006). The main fish species found were white perch (*Morone americana*), gizzard shad (*Dorosoma cepedianum*), blueback herring (*Alosa aestivalis*), and channel catfish. Striped bass (*Morone saxatilis*) and American shad (*Alosa sapidissima*), commercially important fishes, were found in low numbers. Earlier impingement studies also observed gizzard shad and white perch, many of which were juveniles, stunted, or already diseased prior to impingement (Pepco 1982).

The benthic macroinvertebrate community in the tidally influenced river near the Plant includes a mix of freshwater organisms that are tolerant of exposure to low salinity and estuarine organisms that are tolerant of fresh water (<http://www.dnr.state.md.us>). Benthic organisms are affected by oxygen depletion that occurs in the bottom waters during summer months. The freshwater tidal Potomac does not support shellfish of commercial value, but it does include large populations of Asiatic clams (*Corbicula fluminea*), an undesirable invasive species (EPA 1997).

3.4.2.2 Anacostia River

The Anacostia River estuary has some of the poorest water quality in the Chesapeake Bay system and is, thus, in a degraded ecological condition (EPA 1995). Many miles of stream habitats have been severely degraded by urbanization, which has profoundly altered the flow, shape, water quality, and ecology of streams in the watershed. Stressors of concern in the river are described in Section 3.3.2.2.

Urbanization has caused the loss of nearly 50 percent of the forest cover in the basin, including much of the stream-side or riparian vegetation and other wetlands. (See Section 3.4.3.)

As a large, tidally influenced freshwater river like the Potomac, the Anacostia also has the capacity to support many diadromous as well as resident fish species. Even though the river has been degraded by the effects of human activities, a wide variety of fish species still occurs in it. Numerous man-made fish barriers, however, block migration of fish.

The tidal reach of the river has chronically low dissolved oxygen levels that threaten aquatic life. (See Section 3.3.2.2.) The periodic lack of dissolved oxygen is the likely reason that substantial clam populations are absent from the river (EPA 1997). The macroinvertebrate communities in the river are severely degraded compared to those in the Potomac.

Implementation of the Anacostia Watershed Restoration Agreement (Section 3.3.2.2) has resulted in some improvement in aquatic habitat conditions (EPA 1997, Anacostia Watershed Restoration Committee 2004).

3.4.2.3 Rock Creek

As the largest stream in D.C., Rock Creek has historically supported substantial populations of recreationally important fish species and, through its direct connection to the Potomac River, large numbers of anadromous species (EPA 1995). The present anadromous fish populations and resident fish communities reflect the harmful effects of polluted runoff, barriers to fish movement, and over fishing. Nonnative fish species (e.g., largemouth bass, bluegill [*Lepomis macrochirus*], carp [*Cyprinus carpio carpio*]) now constitute a significant part of the fish community. Some species that were historically present in Rock Creek have apparently been extirpated from the watershed (e.g., white perch, trout-perch [*Percopsis omiscomaycus*]). In contrast, populations of anadromous alewife (*Alosa pseudoharengus*) and blueback herring appear to be healthy. Even though instream impediments to fish movement probably affect these species and prevent them from passing far upstream, schools of hundreds of individuals occur at several locations.

In contrast to the mainstem, fish communities in tributaries of Rock Creek are small or absent (EPA 1995). Episodic water quality problems (e.g., low flows, flooding, scouring during storm events) and polluted runoff are likely contributing factors.

Overall, the condition of the benthic macroinvertebrate communities in Rock Creek is poor. However, the creek contains several spring-dependent species of isopods, ostracods, and amphipods (EPA 1995), including one amphipod that is listed as an endangered species (Section 3.4.4.1).

3.4.2.4 Patuxent River

Stream quality for fish communities in the Patuxent River is poor in over 50% of the stream miles; only 18% are considered to be in good condition for fish (Maryland DNR undated-a). The Patuxent River watershed includes an estimated 1.1 million fish of 44 species in its wadeable streams. Four species in the basin are at risk of local extinction: American brook lamprey (*Lampetra appendix*), glassy darter (*Etheostoma vitreum*), stripeback darter (*Percina notogramma*), and warmouth (*Lepomis gulosus*). The wadeable tributary streams of the watershed serve as a nursery for the five gamefish species that are found there (i.e., largemouth

bass, smallmouth bass, chain pickerel [*Esox niger*], brown trout [*Salmo trutta trutta*], and rainbow trout [*Oncorhynchus mykiss*]), as most individuals are not of harvestable size.

3.4.2.5 Chesapeake Bay organisms

The sheltered waters of Chesapeake Bay, the largest estuary in the U.S., are exceptionally productive. The Bay is a complex ecosystem that provides homes, protection, and food for many species, including fish, shellfish, and turtles (CBP undated, Alliance for the Chesapeake Bay undated).

Bay grasses, a form of naturally submerged aquatic vegetation, are important to the Chesapeake Bay ecosystem (CBP undated). Bay grasses produce oxygen, supply food for many species (especially waterfowl), offer shelter and nursery habitat for fish and shellfish, reduce wave action and shoreline erosion, absorb excess nutrients (e.g, nitrogen, phosphorus), and trap sediments.

More than 300 species of fish, including 32 year-round species, live in the Bay and its tributaries or use its waters as they migrate along the Atlantic Coast (Alliance for the Chesapeake Bay undated). Migrating fish can, however, no longer reach many stream habitats due to the presence of dams, inadequate culverts, and other barriers to their passage (EPA 1997).

The Bay acts as a nursery for crabs, oysters, and many other species of shellfish (Alliance for the Chesapeake Bay undated). While many of these species, particularly blue crabs (*Callinectes sapidus*), are still commercially important, oyster (*Crassostrea virginica*) populations have declined to about one percent of historical levels.

3.4.2.6 Chesapeake Bay stresses

Hydrological changes, sedimentation, and pollutant loading have degraded aquatic habitats throughout Chesapeake Bay. The cooperative efforts and guidance of the Chesapeake Bay Program have led to improvements, including reduced levels of nutrients and sediments in the Bay and increased availability of dissolved oxygen for the Bay's aquatic biota, but they have not fully restored the health of the Bay (CBP undated). The biggest problems currently facing the Bay's ecosystem and making restoration difficult are excess nutrients, chemical contaminants, air pollution, and landscape changes. (See Section 3.3.2.5.)

Nutrient loading contributes to excessive algal growth, which in turn depletes dissolved oxygen and reduces water clarity. Harmful blooms of *Microcystis* and other cyanobacteria (blue-green algae) that are toxic to humans and other mammals can occur in the fresh-water and low-salinity portions of the Bay and in tributary estuaries (e.g., the Potomac River). In addition, suspended sediment loading and the presence of toxic substances in Bay sediments stress Bay biota.

3.4.3. Wetlands and Riparian Habitats

Wetlands act as water-storage basins and provide vital habitats for a rich diversity of wildlife, including threatened and endangered species (EPA 2006d). They also reduce flooding and storm damage, minimize erosion of uplands, improve water quality by filtering pollutants, and support tourism and the hunting and fishing industries.

Many of the wetlands in the region have been degraded and are of poor quality, but some continue to provide habitat for waterfowl, wildlife, fish, and shellfish (EPA 1995).

Much of the area (e.g., the District of Columbia) was initially built by filling in extensive areas of marshes and swamps along the Potomac and Anacostia rivers (EPA 1997). Such wetlands originally comprised about half the area within the boundaries of the city, totaling more than 9,600 acres (3,900 ha) in 1790. In the early 1990's only 845 acres (342 ha) of wetlands remained in the District, a decrease in area of more than 90% in 200 years.

Riparian, or stream side, vegetation is especially important to the integrity of the District of Columbia ecosystem because it buffers aquatic resources from developed areas and provides habitat for terrestrial species near water (EPA 1997). Contiguous riparian habitats also provide migration corridors for wildlife, a critical factor in urbanized environments. Because Rock Creek Park surrounds the entire length of Rock Creek in the District and Maryland parks surround most of its length beyond the District, the area along Rock Creek is the most important terrestrial and riparian resource in the city.

Within the Anacostia River watershed nearly 75 percent of the freshwater wetlands have been destroyed. Of the original 2,600 acres (1,100 ha) of emergent tidal wetlands in the watershed, less than 100 acres (40 ha) remained in the early 1990s (EPA 1995); by 2003 ongoing restoration efforts had increased the area of tidal wetlands to 123 acres (50 ha) (Anacostia Watershed Restoration Committee 2004). Parklands along the Anacostia River do not provide benefits similar to those along Rock Creek because they are not protected natural areas, but rather are reclaimed wetlands in the form of sparsely wooded lawns. They have the potential, however, to provide such benefits, especially if riparian restoration is coordinated with ongoing restoration of wetlands.

The Federal government maintains 80% of the property bordering the Potomac River, Anacostia River, and Rock Creek drainage basins in the District of Columbia, thus providing some protection to their riparian areas (EPA 1997).

3.4.4. Special Status Species

3.4.4.1 Federally listed species

The Plant's NPDES permit names three species listed as threatened or endangered under the Federal Endangered Species Act (ESA) that could occur at locations in or near the District of Columbia, including the Potomac River drainage. These are the endangered Hay's Spring

amphipod (*Stygobromus hayi*) and shortnose sturgeon (*Acipenser brevirostrum*) and the threatened bald eagle (*Haliaeetus leucocephalus*).

The Hay's Spring amphipod is restricted to a small area in Rock Creek in D.C., a very specialized habitat, and the species is not found elsewhere (Personal communication between A. Moser, U.S. Fish and Wildlife Service, and M.S. Salk, Oak Ridge National Laboratory, June 19, 2006).

The shortnose sturgeon exists as 19 distinct populations that occupy and spawn in rivers and bays from Canada to Florida (Keeney 2002). The Potomac River is one of several tributaries in the Chesapeake Bay drainage that appear to have suitable habitat for it. The Shortnose Sturgeon Recovery Plan (NMFS 1998) reports that one shortnose sturgeon was captured in 1996 at the mouth of a small creek off the Potomac River about 50 miles (80 km) downstream from the Plant. Between 1996 and 2002 six sturgeon were captured many miles downstream from the Plant in the lower and middle tidal Potomac River (Keeney 2002). Two mature, egg-bearing females were captured in the river in September 2005 and March 2006, suggesting that a spawning population continues to exist in the river system (Appendix D). The female caught in September 2005 overwintered in a creek approximately 24 miles (39 km) downstream of the Plant. Population dynamics in the Potomac River have not been documented, but it is likely that they migrate past the Plant in the spring (March - June) while moving to and from the presumed spawning grounds near Little Falls, Maryland (about 11 miles [18 km] upstream from the Plant). It is unknown if the sturgeon occur in this region of the river during other times of the year. However, if appropriate forage items are present, they could live in the area in the summer and fall. The shortnose sturgeon has not been reported among the species impinged by the Plant (Personal communication between D. Knight, Mirant, and M.S. Salk, Oak Ridge National Laboratory, July 24, 2006).

While a pair of bald eagles lived for several years about two miles (3 km) south of the Plant near the Woodrow Wilson Bridge (WWBP 2006a) until the recent death of the female (WWBP 2006b), bald eagles are only rarely seen near the Plant (Personal communication between D. Knight, Mirant, and M.S. Salk, Oak Ridge National Laboratory, July 24, 2006). (See Figure 3.3-3.)

The Virginia Natural Heritage Resources information database indicates that no Federally listed threatened or endangered species occur in the city of Alexandria, but it names two Federal species of concern⁵ that could occur there: the Northern Virginia well amphipod (*Stygobromus phreaticus*) and Torrey's mountain-mint (*Pycnanthemum torrei*) (VNHR 2006). The amphipod is found only in caves (NatureServe 2006). In Virginia Torrey's mountain-mint occurs in dry, rocky, upland, deciduous woods; along roadsides; and in thickets near streams (NatureServe 2006). There is no suitable habitat for either species on the Plant site.

⁵ "Species of concern" means a species that might be in need of conservation action (FWS 2006). Such species receive no legal protection, and use of the term does not necessarily imply that a species will eventually be proposed for listing.

3.4.4.2 State-listed species

The Virginia Natural Heritage Resources information database indicates that the only state protected species that occurs in the city of Alexandria is the threatened wood turtle (*Glyptemys insculpta*) (VNHR 2006). Wood turtles live along permanent streams during much of each year, but in summer they may roam widely overland and can be found in a variety of terrestrial habitats adjacent to streams, often associated with the margins of woods (NatureServe 2006). There is no suitable habitat for the species on the Plant site.

3.5 Waste Management

Except for small quantities of fly ash that are used beneficially (Section 2.4.3), fly ash from the Plant is disposed of in the Brandywine Fly Ash Facility, a landfill owned and operated by Mirant Ash Management LLC and used solely for disposal of coal combustion ash. The landfill, located in southeastern Prince George's County, Maryland (east of the community of Brandywine) (Figure 2.4.1), is also used for disposal of fly ash from Mirant's Chalk Point Generating Plant on the Patuxent River estuary in southeastern Prince George's County.

The 178-acre (72-ha) site currently used for waste disposal is part of a larger area that was formerly surface-mined for gravel and that has been used for coal combustion ash disposal since 1971. Surrounding land uses include an active sand and gravel mining operation, agricultural fields, forest, a high-voltage electric transmission line, and other landfills. The landfill site has a low-permeability base of compacted native soil (Personal communication between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006) and is equipped with a leachate collection system. Ash is delivered to the landfill by dual-axle dump trucks and is placed and compacted in the landfill in 2-ft (0.6-m) layers. On weekdays during peak power-generation periods the landfill receives approximately 60 truckloads of ash from the two generating stations; average daily ash receipts are approximately 70% of peak daily receipts.

Stormwater runoff and leachate from the landfill drain to collection ponds where a sprinkler pump provides aeration, water quality is monitored, pH is adjusted, and solids settle out before the water is discharged to the upper reaches of Mataponi Creek (a tributary to the fresh water tidal river reach of the Patuxent River) and an unnamed tributary to the creek (Baxter 2006). Dust is controlled by periodically watering haul roads and the active disposal area, using water recycled from the collection ponds (Personal communication between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006).

Landfill site plans limit the final height of the fill to a elevation of 260 ft (79 m) above mean sea level (MSL), or about 70 ft (21 m) above the original land surface grade (Personal communication between A. Wearmouth, Mirant Corporation, and E.D. Smith, Oak Ridge National Laboratory, July 21, 2006). Areas of the landfill that have reached their maximum

design height are capped with a 3-ft (1-meter) thickness of soil and seeded to establish a vegetative cover. In January 2005 the landfill was calculated to have a remaining capacity of 2.07 million yd³ (1.58 million m³), providing sufficient capacity for disposal of the two power plants' projected ash generation for about 7 years, or approximately through the middle of 2012 (GB&B Inc. 2005).

Disposal facilities for coal combustion ash are not subject to state solid waste regulation in Maryland (Personal communication between R. Daniel, Maryland Department of Environment Customer Service Center, and E.D. Smith, Oak Ridge National Laboratory, June 6, 2006), but local zoning requirements and state wastewater regulations apply. The Brandywine facility operates under a series of special exceptions from Prince George's County zoning restrictions. The most recent special exception for 12 years of continued operation was approved by Maryland-National Capital Park & Planning Commission, Prince George's County Planning Department in 1991 (Baxter 2006). In 2005 Mirant filed an application for a 15-year extension to this special exception (Baxter 2006); the application is currently pending.

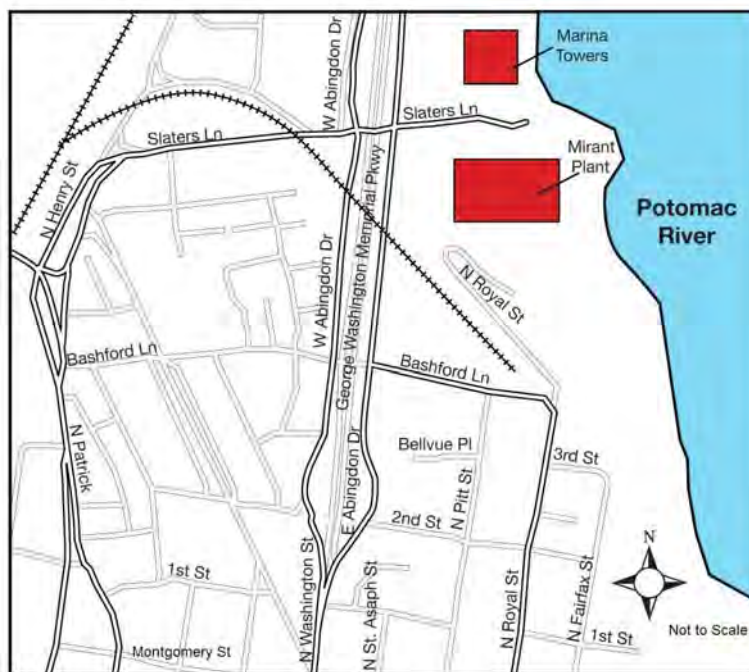
Discharge of wastewater from the site, including storm water runoff, collected leachate, and truck wash water, is permitted under MDE Discharge Permit 02-DP-1389 (NPDES Permit MD0054836), issued by the Maryland Department of the Environment. The current 5-year discharge permit is effective September 1, 2005, to August 31, 2010. The permit limits discharge to a pH range of 6 to 9 pH units, total suspended solids of no more than 35 mg/L as a monthly average and 70 mg/L as a daily maximum, and total iron of no more than 3.5 mg/L as a monthly average and 7.0 mg/L as a daily maximum. Discharge monitoring requirements under the permit include monthly flow and monthly measurements for pH, total suspended solids, hardness, iron, copper, lead, selenium, and zinc. Six groundwater monitoring wells in the vicinity of the landfill are monitored quarterly for pH; total dissolved solids; chloride; sulfate; and dissolved aluminum, cadmium, manganese, copper, iron, lead, silver, and nickel. No surface or groundwater problems are currently identified at the site (Baxter 2006). There have been no regulatory violations since 1996 when a discharge from one of the wastewater ponds exceeded the permit limit for total suspended solids (Personal communication between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006).

3.6 Transportation Resources

The primary transportation activities associated with Plant operations are (1) trains traveling to and from the Plant to deliver coal and trona and (2) trucks traveling to and from the plant to remove ash. The following sections discuss the affected local environment for these rail and road operations.

3.6.1 Rail

Trains enter and exit the Plant to deliver coal and trona via a short rail spur from the CSX, Inc., main rail line located west of North Henry Street (Figure 3.6-1). The City of Alexandria allows the Plant to conduct rail operations during two daytime periods (11 a.m. to 12 p.m. and 1 p.m. to 3 p.m.) and one nighttime period (7 p.m. to 11 p.m.) from Monday through Saturday. (The Plant does not receive rail deliveries on Sundays.) Daytime rail operations involve removing empty rail cars from the Plant during each of the two daytime periods to avoid blocking vehicular traffic on the George Washington Parkway (Figure 3.6-1). Nighttime rail operations involve deliveries of coal and trona (Personal communication between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006).



ORNL 2006-G00959r/g

Figure 3.6-1. Access routes near the Mirant Plant.

3.6.2 Road

Trucks enter and exit the Plant to remove ash via a gated entrance located on North Royal Street (Figure 3.6-1). The trucks haul ash from the Plant to the Brandywine Fly Ash Facility in Prince George's County, Maryland (Figure 2.4-1).

From the Plant the trucks travel south on North Royal Street, then west on Montgomery Street (Figure 3.6-1). Neither the Virginia Department of Transportation nor the City of Alexandria maintains data on annual average daily traffic⁶ or level-of-service (LOS)⁷ for North Royal Street, but it is a local street with relatively little traffic and an existing level-of-service (LOS) at or near "A" (Personal communication between B. Garbacz, Transportation Engineer,

⁶ The annual average daily traffic is "an estimate of typical daily traffic on a road segment for all days of the week, Sunday through Saturday, over the period of one year" (VDOT 2004).

⁷ Level-of-service (LOS) is "a standard measurement used by transportation officials which reflects the relative ease of traffic flow on a scale of A to F, with free-flow being rated LOS-A and congested conditions rated as LOS-F" (FHWA 2006).

City of Alexandria, Virginia, and J.W. Saulsbury, Oak Ridge National Laboratory, May 26, 2006). On Montgomery Street annual average daily traffic is 3,800 vehicles (VDOT 2004).

Once the trucks reach the intersection of Montgomery Street and Henry Street (State Route 1) (Figure 3.6-1), they travel south on Henry Street to access Interstate 495 (I-495 or the Capital Beltway) (Figure 2.4-1). The trucks then travel east on I-495 North, crossing the Potomac River on the Woodrow Wilson Memorial Bridge, which serves as a major connector between Virginia and Maryland (Figure 3.3-3). On entering Maryland, trucks exit onto Maryland Route 5 and travel south. The trucks continue to travel south on Maryland Route 381 (Brandywine Road) to North Keys Road, on which the Brandywine facility is located. Table 3.6-1 lists the existing traffic volumes on each of these roads between Henry Street in Alexandria and the Brandywine facility in Maryland.

Table 3.6-1. Roads traveled by the ash removal trucks between Henry Street and the Brandywine Fly Ash Facility

Road	Segment	Annual Average Daily Traffic
Henry Street (Route 1)	Southbound to I-495 North (Capital Beltway)	22,000 to 25,000
I-495 North	Eastbound into Maryland via the Woodrow Wilson Memorial Bridge	154,000
I-495 North	Eastbound in Maryland to Maryland Route 5	142,925 to 174,800
Maryland Route 5	Southbound to Maryland Route 381	62,450 to 112,050
Maryland Route 381 (Brandywine Road)	Southbound to North Keys Road	4,850 to 12,150
North Keys Road	Southbound to the Brandywine Fly Ash Facility	No data available

Sources: VDOT 2004; MDOT 2005

The road network used to transport ash to the landfill is affected by ongoing construction activities associated with the Woodrow Wilson Bridge Project (WWBP 2006a). This project, which is scheduled for completion in December 2012, involves a series of roadway and interchange improvements along a 7.5-mile-long (12-km-long) segment of I-495 that extends from the Telegraph Road interchange in Virginia to the Route 210 interchange in Maryland. The project's centerpiece, widening and improving the Woodrow Wilson Memorial Bridge, is scheduled for completion in December 2008.

Access to the Brandywine Fly Ash Facility from North Keys Road is via a private road that is shared by an adjoining sand and gravel mining and wet processing facility. During peak winter and summer months total hauling operations at the Brandywine Fly Ash Facility consist of approximately 60 truckloads per day. This total includes trucks from the Plant and from Mirant's Chalk Point Power Plant in Prince George's County, Maryland. Typical weekday

haulage activity at the Brandywine facility is approximately 70 percent of the seasonal peaks (Baxter 2006).

There are some existing traffic problems on Maryland Route 381, which is used to access the Brandywine facility. Although the State of Maryland's accident records indicate that this road operates without any significant safety deficiencies, certain intersections along Maryland Route 381 function inadequately and have a low LOS based on existing traffic volumes (Baxter 2006).

In April 2005 Mirant filed with the Maryland-National Capital Park and Planning Commission an Application for Special Exception for a Sanitary Landfill (Fly Ash) (Baxter 2006). That application includes information about transporting ash to the Brandywine facility. Mirant's Application was reviewed by the Maryland Department of Transportation State Highway Administration and the Prince George's County Department of Public Works and Transportation. The Department of Public Works and Transportation conducted a traffic study for Mirant's Application in which it assumed that there would be "an increase in through traffic percent along key roadways in the study area." The traffic study examined impacts for seven intersections under three scenarios:

- existing traffic conditions,
- the addition of 13 background developments whose impact would affect some or all of the study intersections, and
- traffic volumes representing total background conditions combined with projected facility site trip generation (the 20-year build-out projection).

Analysis of this third scenario (which includes Mirant's Application, as well as 13 other "background" developments over a 20-year period) indicated impacts on the seven intersections as listed in Table 3.6-2. Ash hauling associated with pre-shutdown operations at the Plant was a minor contributor to these existing traffic problems.

The Department of Public Works and Transportation traffic study notes that the State Highway Administration has required Mirant to address the failing levels of service at these intersections along Maryland Route 381. In particular, the study notes that the intersection of Maryland Route 381 and U.S. Highway 301 "operates inadequately based on existing traffic volumes (LOS-E in the morning) and will worsen significantly with the inclusion of approved background developments." The study adds that pursuant to State Highway Administration's comments, Mirant "has offered no improvements that would ameliorate the inadequacies at that intersection" (Baxter 2006).

Table 3.6-2. Traffic impacts projected in Mirant's *Application for Special Exception* for the road intersections used to access the Brandywine Fly Ash Facility

Intersection	Level-of-Service during after-midnight and morning hours	Level-of-Service during afternoon and evening hours
North Keys Road/Gibbons Church Road (unsignalized)	B	A
Maryland 381/North Keys Road (unsignalized)	<i>F</i>	C
Maryland 381/U.S. 301 (signalized)	<i>F</i>	<i>F</i>
Maryland 381/Baden Westwood Road (unsignalized)	<i>F</i>	B
Maryland 381/Croom Road (unsignalized)	<i>F</i>	<i>F</i>
Link—Maryland 381 (U.S. 301–North Keys Road)	E	D
Link—Maryland 381 (Croom Road–North Keys Road)	C	C

Figures in ***boldface italics*** represent failing levels of service.

Source: Baxter 2006

3.7 Minority and Low-Income Populations

Executive Order 12898, *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations*, directs each Federal agency to identify and address the “disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority and low-income populations.” The Council on Environmental Quality (CEQ) guidance on environmental justice (CEQ 1997) states that a “minority population” should be identified where either: “(a) the minority population of the affected area exceeds 50 percent or (b) the minority population percentage in the affected area is meaningfully greater than the minority population percentage in the general population or appropriate unit of geographical analysis.” The CEQ guidance defines “low-income” using statistical poverty thresholds from the Bureau of Census Current Population Reports, Series P-60 on Income and Poverty.

For this analysis DOE examined the 2000 U.S. Census data to identify any minority or low-income populations in census tract⁸ (CT) 2018.01, in which the Plant is located (Figure 3.7-1), and the four block groups⁹ within CT 2018.01. DOE focused on CT 2018.01 because its boundaries encompass the geographical distribution of the greatest air quality impacts from the

⁸ The U.S. Census Bureau defines census tracts as small, relatively permanent statistical subdivisions of a county. Census tracts average about 4,000 inhabitants and are designed to be relatively homogeneous units with respect to population characteristics, economic status, and living conditions. Census Tract 2018.01 has a total population of 4,727.

⁹ The U.S. Census Bureau defines block groups as subdivisions of a census tract. Block groups are the smallest geographic unit for which the Census Bureau tabulates sample data.

Plant. To identify minority and low-income populations within CT 2018.01 and its block groups, DOE defined a “meaningfully greater” population as one that had a minority or low-income percentage at least 10 percentage points higher than the percentages for the city of Alexandria, the state of Virginia, or the United States (whichever is lower).¹⁰ Thus, based on the data in Table 3.7-1, DOE identified minority populations as those that have a minority percentage of at least 39.8% (10 percentage points higher than the state of Virginia) and low-income populations as those that have a low-income percentage of at least 18.9% (10 percentage points higher than the city of Alexandria).

As indicated in Table 3.7-1, the percentages of the total population in CT 2018.01 (population 4,727) that are classified as minority (27.2%) and low-income (11.1%) do not exceed DOE’s threshold for identifying either minority or low-income populations. However, block group 3, which is located south of the Plant (Figure 3.7-1) and has a total population of 1,368, exceeds DOE’s low-income threshold. Similarly, block group 4, which is located southwest of the Plant (Figure 3.7-1) and has a total population of 620, exceeds DOE’s minority threshold. Therefore, block groups 3 and 4 of CT 2018.01 contain minority and low-income populations that meet the DOE thresholds, while block groups 1 and 2 (populations of 1,650 and 1,085, respectively) do not.

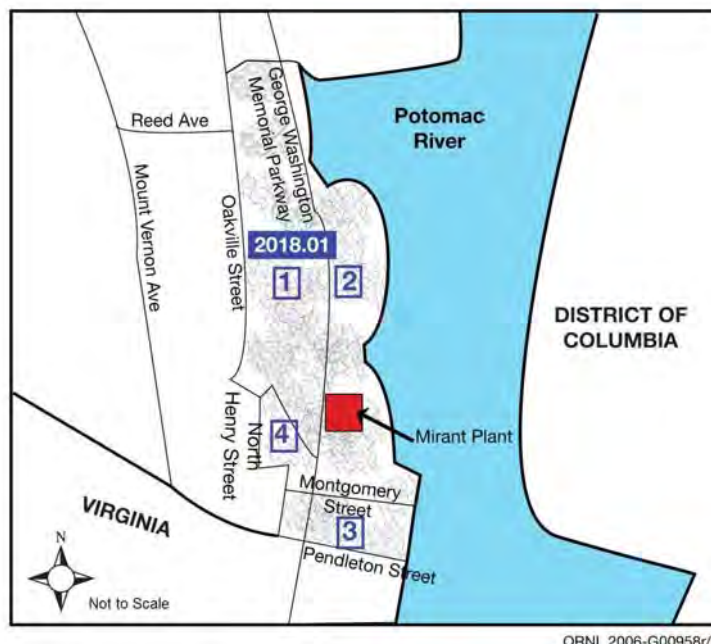


Figure 3.7-1. Block Groups 1-4 within Census Tract 2018.01.

¹⁰ The “10 percentage point” criterion is used here because it is large enough to indicate the presence of a minority or low-income population when compared to a large geographic area (i.e., the state or the nation), yet small enough to indicate minor differences in percentages among several census tracts or block groups in a small geographic area. Note that the use of a more conservative criterion, such as 5 percentage points, would not change which block groups are identified as minority or low-income populations.

Table 3.7-1. Minority and low-income data for census tract 2018.01 and its block groups (See Figure 3.7-1)

Location	Percent minority ^a	Percent low-income ^b
United States	30.9	12.4
State of Virginia	29.8	9.6
City of Alexandria	46.3 [‡]	8.9
Census tract 2018.01	27.2	11.1
Block group 1	18.9	5.0
Block group 2	6.3	9.5
Block group 3	37.8	23.3 [‡]
Block group 4	60.0 [‡]	3.4

^a Includes all persons who identified themselves as not “white alone,” plus those who identified themselves as both “white alone” and “Hispanic or Latino.”

^b Represents individuals below the poverty level as defined by the U.S. Census Bureau.

[‡] Minority or low-income population based on the DOE thresholds for percent minority or low-income.

Source: U.S. Census Bureau 2006.

4. PLANT OPERATIONS, ASSUMPTIONS, AND ENVIRONMENTAL CONSEQUENCES

This chapter begins by describing general Plant operations as authorized by the DOE Order. Next, this chapter describes the information and assumptions that DOE used to assess the impacts of the Plant under the DOE Order and a potential extension of the Order until the new 230-kV transmission lines are in service. Finally, this chapter assesses the impacts to air, human health, water, ecological resources, waste management, transportation resources, and minority and low-income populations as a result of the Order and a potential extension of the Order until the new 230-kV transmission lines are in service.

4.1 General Plant Operations as Authorized by the DOE Order

The DOE Order consists of 285 days, from December 20, 2005, to October 1, 2006. Just before the Secretary issued the Order, Mirant operated Unit 1 on an 8-8-8 basis (that is, in any given 24-hour period, it ran for eight hours at up to its maximum level of 88 MW, ran for up to eight hours at its minimum level of 35 MW, and did not run for at least eight hours), and began using trona and low sulfur Colombian coal, alone or in combination.

4.1.1 Operations as Authorized by the DOE Order until the Administrative Compliance Order (ACO)

At the time the Order was issued, Mirant had one operational trona injection unit that serviced only the Unit 1 boiler. A second trona unit became operational on January 22, 2006, and a third on March 20, 2006. Except during transmission line outages (Table 1.3-1), Mirant operated only boilers that had trona units. By April 28, 2006, Mirant had operational trona injection units installed on all five boiler units.

On January 4, 2006, DOE authorized Mirant to operate each of the two load-following or cycling units at the Plant (i.e., Units 1 and 2) up to 16 hours per day. Each unit was authorized to operate 8 hours at minimum load and up to an additional 8 hours at maximum load. In addition, DOE authorized Mirant to operate any one of the three baseload units continuously without constraint as to load or operating hours. According to Mirant's proposed operating plan, each baseload unit would operate for approximately two weeks before another baseload unit began a two-week operating period.

In January 2006, due to transmission line outages for maintenance, Mirant operated the Plant to meet the entire Central Washington, D.C., load for 21 days. No line outages have occurred since those in January. Between January and May, DOE continued to weigh other options that were available to Mirant to comply with the Order and consulted with EPA on options to increase electricity reliability while ensuring environmental protection.

4.1.2 Operation under the ACO

EPA issued its ACO to Mirant on June 1, 2006. On June 2, 2006, DOE directed Mirant to operate under the ACO during non-line outage situations, for the purpose of providing electricity reliability, and to continue operation in accordance with the DOE Order in line-outage situations.

4.1.2.1 Operations during non-line outage situations

Daily predictive modeling. Upon installation of three SO₂ monitors¹¹ the ACO directs Mirant, in non-line outage situations, to operate under daily predictive modeling. Under daily predictive modeling the Plant operators acquire the National Weather Service forecast for the next day for Ronald Reagan Washington National Airport and use that forecast along with their planned operating parameters as inputs to a computer modeling run for the following day using AERMOD Default¹². If the modeling results indicate that operating the Plant under those conditions would not cause a modeled exceedance of the 3- and 24-hour average SO₂ and PM₁₀ NAAQS limits, operators may run the Plant on that day using those parameters. If the results indicate that operation of the Plant would cause a modeled exceedance for these pollutants, the operators must adjust the planned operating parameters and rerun the model using the same weather forecast. The operators must continue to adjust their planned operating parameters and rerun the model until the results indicate no modeled exceedance of these pollutants. The operators then will operate the Plant the next day using those parameters. Thus, under this scenario the Plant can operate each day up to the maximum level allowed by the weather forecast for that day. The ACO only requires daily predictive modeling for PM₁₀ when Mirant operates four or five units. Mirant is required to assume a PM₁₀ emission rate of 0.055 lb/MBtu and to adjust operations to prevent a modeled exceedance for PM₁₀.

Other requirements of the ACO. In addition to daily predictive modeling, the ACO requires Mirant to install an audible alarm in the Plant's control room that will sound when the ambient concentration of SO₂ at any monitor reaches specified levels. When an alarm sounds, Mirant must make operational changes (e.g., increase use of trona, decrease operating level) and observe the effect of those changes on the level of SO₂ measured at the monitors. The ACO uses this alarm system to monitor the Plant's compliance with the annual SO₂ NAAQS limit. The

¹¹ Until June 20, 2006, when three newly installed SO₂ monitors were functioning, Mirant operated under the constraints detailed in Table 1 in the ACO. (See Appendix B.) These constraints included, for example, restrictions on number of hours of operation and SO₂ emission rate during each calendar day. For example, on days when Units 1 and 3 were operating, each unit was required to achieve a 24-hour average SO₂ emission rate no higher than 0.24 lb/MBtu and a 3-hour rolling rate no higher than 0.51 lb/MBtu, and Unit 1 was required to operate for no more than 8 hours per day above minimum power and spend at least 8 hours per day off.

¹² AERMOD Default means Version 04300 of the AERMOD computer model, currently approved for general use by EPA in accordance with 40 CFR Part 51, Appendix W, to predict NAAQS compliance. See the AERMOD text box in Section 4.3.1.

ACO also directs Mirant to undertake a “Model Evaluation Study” (MES) (text box) “to determine the best performing model for predicting the computer-modeled ambient air quality impacts” from Plant operations. To provide data for the MES and to support the alarms, Mirant installed six SO₂ monitors in locations identified in the ACO. (See Appendix B.) Lastly, the ACO puts a NO_x limitation on the Plant; at all times Mirant may not emit more than 3,700 tons (3,400 metric tons) of NO_x per year.

4.1.2.2 Operations during line outage situations

The ACO directs Mirant, in line-outage situations, to follow the DOE Order, but requires Mirant to “take all reasonable steps to limit the emissions of PM₁₀, NO_x and SO₂ from each boiler, including operating only the number of units required to meet PJM’s directive and optimizing its use of trona injection to minimize SO₂ emissions.” Further, the ACO requires that Mirant achieve “80% reduction of SO₂ emissions unless: 1) Mirant demonstrates ... that 80% reduction is not necessary to achieve compliance with the NAAQS; or 2) Mirant demonstrates that 80% reduction is not logistically feasible because of such factors as the quantity of available trona and the predicted duration of the outage.” If Mirant demonstrates that 80% removal is not logistically feasible, it is required to submit a plan to EPA for optimizing its use of trona. However, as described in Section 4.3.1.1 and Section 5.3.1, DOE assumed 50% removal of SO₂ emissions in assessing impacts under the DOE Order and a potential extension of the Order.

Model Evaluation Study

The objective of the MES is to determine the best performing model for predicting the computer-modeled ambient air quality impacts from Plant operations. The MES proceeds by comparing the air quality impacts predicted by the AERMOD Default and those predicted by AERMOD EBD computer models to actual measured SO₂ concentrations in order to determine the better performing model. AERMOD Default is Version 04300 of AERMOD computer model, currently approved for general use by EPA. AERMOD EBD means the standard AERMOD computer model with modified direction-specific equivalent building dimensions derived from a wind tunnel study. Mirant submitted an MES protocol to EPA in July 2006 and submitted the results of the wind tunnel study to EPA in August 2006. If EPA and the VDEQ approve AERMOD EBD, Mirant must use it in its predictive modeling for the remainder of the MES period.

Mirant is to compare the actual data from the six monitors to the results of the two computer models. At the end of the study EPA and the VDEQ expect to determine which model is *best performing*. The best performing model will then be used to develop permanent emission limits for the Plant.

4.2 Assumptions and Data Used in SEA to Model Plant Operations

To the extent possible, DOE’s assessment of the environmental impacts of Plant operations under the Order is based on actual operating data. However, the Plant has had several different modes of operation under the Order, and data are not available for all parameters.

Therefore, it was necessary to make some assumptions in order to assess the impacts of the Order and of the potential extension of the Order. This section describes operations under the Order and the assumptions that DOE used to estimate the environmental consequences.

4.2.1 Pre-Shutdown Operations

Before it shut down on August 25, 2005, the Plant operated its five units without SO₂ emissions controls. The Plant generated electricity at an annual average rate of 210 MW and burned about 837,000 tons (755,000 metric tons) of coal per year. Generation varied seasonally, with the highest generation occurring in the summer months when demand for air conditioning is high (Figure 4.2-1).

DOE used hourly, unit-by-unit electricity generation data, provided by Mirant, to model operations of the Plant. DOE used SO₂ emission factors it developed by analyzing detailed operation and emission data for the period December 20, 2005, through March 31, 2006. DOE assumed that the Plant emitted SO₂ at a rate of 1.05 lb/MBtu and that it emitted NO₂ at a rate of 0.35 lb/MBtu for Units 1 and 2 and 0.26 lb/MBtu for Units 3, 4, and 5.

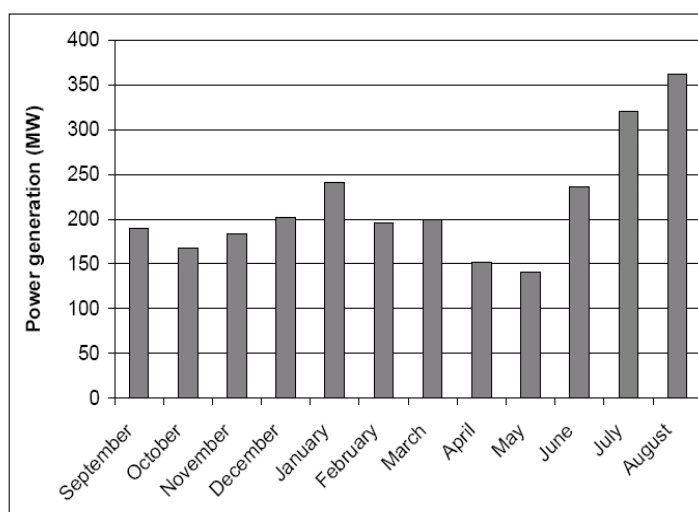


Figure 4.2-1. Monthly average power generation for September 2004 through August 2005.

4.2.2 Pre-Order Operations

Before the Secretary of Energy issued the Order, Mirant was operating Unit 1 in an 8-8-8 mode (in any given 24-hour period, the unit ran for up to eight hours at power levels up to its maximum level of 88 MW, ran for eight hours at its minimum level of 35 MW, and did not run for eight hours) and had begun using trona injection and low-sulfur coal in varying quantities. If the Order had not been issued, it is likely that Mirant would have continued to restart additional units at the Plant with the further installation of trona injection units. However, because it is impossible to know exactly what would have happened if the Order had not been issued, DOE is providing this “pre-Order” mode of operations as a basis for comparing impacts under the Order.¹³

¹³ Because Mirant did not provide DOE with operations data for periods before December 20, 2005, and (continued...)

During the pre-Order mode, the Plant's Unit 1 operated for 16 hours per day with intermittent use of Colombian coal and/or trona injection. A typical day started at about 4 am with the unit being brought up to operating temperature by burning oil for about two hours. At about 6 am the unit was switched to coal and began generating electricity. The unit would reach a level close to its 88 MW capacity in about five hours, around 11 am. The unit would continue at that high power level through the afternoon and evening before making the transition to shut down status by about 10 pm. This is the 8-8-8 mode of operation.

During the pre-Order period Unit 1 consumed about 540 tons (490 metric tons) each day of coal with an average heat content of 12,000 Btu/lb and a heat rate of 12.9 million Btu per MWh (MBtu/MWh). On average, the unit emitted about 10,300 lb (4,700 kg) of SO₂ and about 4,300 lb (1,900 kg) of NO_x per day. SO₂ emission rates varied within the period due to trona injection and burning of coal with different sulfur contents. At this rate of coal consumption, one train containing 40 rail cars with 100 tons (91 metric tons) of coal per rail car could provide a week's worth of coal to the Plant. On a day when the Plant consumed 540 tons (490 metric tons) of coal that was on average 67% by weight carbon, it released about 1,300 tons (1,200 metric tons) of CO₂.

According to discharge monitoring reports that Mirant prepared for submission to EPA (Personal communication between A. Wearmouth, Mirant Corporation, and E.D. Smith, Oak Ridge National Laboratory, July 21, 2006), during December 2005 discharges to the Potomac River of cooling water and treated in-plant effluents averaged 94 million gal (356,000 m³) per day. The reported maximum thermal discharge to the river was 969 MBtu per hour.

4.2.3 Operations under the Order and Potential Extension

Mirant provided DOE with hourly records of power plant operations for the period December 20, 2005, through March 31, 2006. These records include power production, stack gas parameters (e.g., flow rate, temperature, percent CO₂, opacity), pounds of NO₂ released per million Btu, pounds per hour of NO₂ released, pounds of SO₂ released per million Btu, and pounds per hour of SO₂ released. Table 4.2-1 is a summary of plant operations through March 31, 2006.

Mirant also supplied data on wastewater discharges for all months through June 2006 and data on total coal consumption and fly ash generation during the 3-month period March through May 2006.

The operating records described above allowed DOE to estimate plant operational parameters for each unit. DOE used those parameters to model plant operations during the Order and during a potential extension of the Order.

¹³ (...continued)

because Mirant continued its pre-Order (8-8-8 mode) operations through December 23, DOE used December 20 through 23 to represent pre-Order operations.

Table 4.2-1. Plant operation from December 21, 2005, through March 31, 2006

Dates	Operating mode
December 20- 23, 2005	Unit 1 operated with Colombian coal and trona testing
December 24, 2005	No data available
December 25 - 31, 2005	Unit 1 operated without using low sulfur coal or trona
January 1, 2006	No data available
January 2 - 6	Unit 1 operated without using low sulfur coal or trona
January 7 - 19	All five units operated as directed by PJM for a transmission line outage; only Unit 4 had trona injection
January 20	Only Unit 4 operated
January 21 - 28	All five units operated as directed by PJM for a transmission line outage; trona injection on Units 3 and 4
January 29 - February 15	Units 1 and 4 operated with trona injection
February 16 - 17	Only Unit 4 operated
February 18 - 21	Unit 3 and Unit 4 operated
February 22 - 25	Unit 1 and Unit 3 operated
February 26 - 27	Only Unit 3 operated
February 28 - March 8	Unit 2 and Unit 3 operated
March 9	Only Unit 4 operated
March 10 - 21	Unit 4 and Unit 5 operated
March 22	Only Unit 4 operated
March 23 - 31	Unit 3 and Unit 4 operated

Note: After January 28, only units employing trona injection were operated. Because Mirant found the Colombian coal unsuitable for use at the Plant, after the initial supply was consumed, Mirant used only trona injection to control SO₂ emissions.

For the purpose of evaluating impacts for which actual emissions data are not available, DOE assumed that impacts could be scaled to power production and coal use based on pre-August 2005 data (Section 4.2.1). During the year before shutting down in August 2005, the Plant generated power at an average rate of approximately 210 MW and consumed about 832,000 tons (755,000 metric tons) of coal.

Assumptions for operations from December 20, 2005, through June 30, 2006. For the period through March 31, DOE used hourly emissions data provided by Mirant to model air emissions. For the two days for which data were not provided, DOE assumed operations were identical to the preceding day. For this period DOE used historical weather data for the specific days of operation acquired from the National Weather Service.

Beginning with April, DOE made assumptions on operating modes based on information provided by Mirant. In operating plan supplements that Mirant supplied to DOE on January 13, 17, and 24 and February 6 and 16, 2006, Mirant described combinations of SO₂ emission rates and limits on hours of operation for all combinations of two units that its modeling determined would not cause any NAAQS exceedance. To model the air quality impacts of operations during the period April 1 through May 31, 2006, DOE assumed that Mirant operated the Plant to the maximum level described in those supplements.

Assumptions for operations from July 1 through September 30. On June 2, 2006, DOE directed Mirant to operate the Plant in compliance with the ACO. The ACO directed Mirant to operate the Plant within a set of constraints on operation hours and SO₂ emission rates enumerated in the ACO until Mirant met the requirements to operate in accordance with daily predictive modeling. For the purposes of this SEA DOE assumed that the Plant operated June 1 through June 30, 2006, in a manner that produced the maximum electrical power while being in compliance with the table of operational limits in the ACO.¹⁴

DOE assumed that after June 30 Mirant operated at the maximum level of power generation allowed under daily predictive modeling, as described in Section 4.1.2.1, and that, except during line-outage periods, this mode of operation continued through the duration of the Order and during a potential extension of the Order through 2007. The Plant generates electric power in response to demand, at levels requested by PJM. In order to estimate how much power might be generated during non-line outage situations when operating under daily predictive modeling, DOE used the record of the last year of historical operation (i.e., the year prior to August 24, 2005; Figure 4.2-1) to produce a scenario that represents levels of operations that might reasonably be expected if it were not for environmental constraints.

Assumptions for a potential extension of the Order.¹⁵ DOE assumed that during non-line outage periods, the Plant would produce as much power as during the year before shutting down in August 2005, while complying with the ACO. Pepco has plans for several transmission line outages that would occur during a potential extension of DOE's Order before the two new 230-kV transmission lines are put into service. Outages are planned from November 27 through December 11, 2006; and February 19 through March 5, May 2 through 15, and May 21 through June 15, 2007. During outage periods DOE assumed that the Plant generated an amount

¹⁴ Table 1 of the ACO specifies maximum operations levels and SO₂ emission rates for individual units and for combinations of two or three units. For operations under the ACO before daily predictive modeling commenced, DOE assumed that the Plant operated two units at all times.

¹⁵ On September 28, 2006 Secretary Bodman issued a temporary extension of the Order until 12:01 a.m., December 1, 2006 to allow time to complete the SEA and consider public comments.

of power equal to the Central D.C. load during the corresponding dates in the year ending on August 31, 2005.¹⁶

Mirant is planning to take units out of service beginning in the fall of 2007 to reconfigure the exhaust stacks. DOE has not modeled these planned unit outages because they are not confirmed.

4.3 Environmental Consequences

Assessment of the environmental consequences of the Order is organized by environmental resource. Consideration of cumulative environmental impacts is incorporated into the individual resource-specific discussions, both implicitly (by considering impacts of the Order in the context of environmental conditions that exist because of past and ongoing actions) and explicitly (by considering the potential impacts of any additional ongoing and reasonably foreseeable future actions identified as having the potential to affect the resource).

4.3.1 Air Quality

Impacts to air quality would occur as the result of pollutants being emitted from the Plant's stacks during operations, as well as from activities at the Plant involving vehicle emissions and fugitive dust associated with the coal pile and the handling of ash. The pollutants of primary concern are SO₂ and particulate matter. Modeled concentrations of SO₂ and PM₁₀ are discussed in Section 4.3.1.3. All other NAAQS pollutants, including PM_{2.5}, and hazardous air pollutants are discussed in Section 4.3.1.5. The emissions from the Plant were modeled for four periods: (1) Pre-shutdown operations, that is, the period before the Plant shutdown in August 2005; (2) Pre-Order operations (Section 4.2.2); (3) the period of the Order, including before

AERMOD

AERMOD is one of the approved models included in EPA's Guideline on Air Quality Models (40 CFR Part 51, Appendix W). It is composed of three parts: AERMAP, AERMET, and AERMOD. AERMOD is a steady-state plume air dispersion model that computes the air concentration of released pollutants at selected receptor points. During each hour modeled AERMOD considers the source characteristics (e.g., amount, temperature, stack exit velocity), atmospheric parameters (e.g., wind speed and direction, atmospheric stability), the relative locations of the source and receptor, and the effects of nearby buildings. The computed hourly concentrations are combined to produce the averaging periods (e.g., 24-hour averages) as requested by the user. AERMAP produces the required input data relative to the receptor grid, including elevation. AERMET processes surface and upper-air atmospheric data and produces the input files required by AERMOD.

¹⁶ Because the Plant was not operating at normal historical levels in the period from August 21-31, 2005, DOE used operational levels for the first 11 days of August 2005 to represent the level that the Plant would likely have operated at if it had been generating power at historical levels during the last 11 days of the month.

the ACO allowed daily predictive modeling (December 20, 2005 through June 30, 2006) and after daily predictive modeling began (July 1 through September 30, 2006); and (4) the period beyond the Order (including the period of the temporary extension of the Order to December 1, 2006) until such time as the new transmission lines are placed into operation (October 1, 2006, through June 30, 2007, or, possibly, December 31, 2007).

4.3.1.1 Modeling methods and assumptions

DOE modeled hourly- and annual-average air concentrations of SO_2 and PM_{10} using the AERMOD system (EPA 2002). (See text box.) AERMOD was used to calculate concentrations for each of the more than 1,700 receptor locations provided by EPA, as shown in Figure 4.3.1-1. The modeled receptor locations include 50-meter intervals along the Plant's fence line. Beyond the fence line, the receptor grid forms a rectangular pattern with the innermost receptors spaced at 100-meter intervals out to a distance of 1,000 meters from the Plant (i.e., the innermost

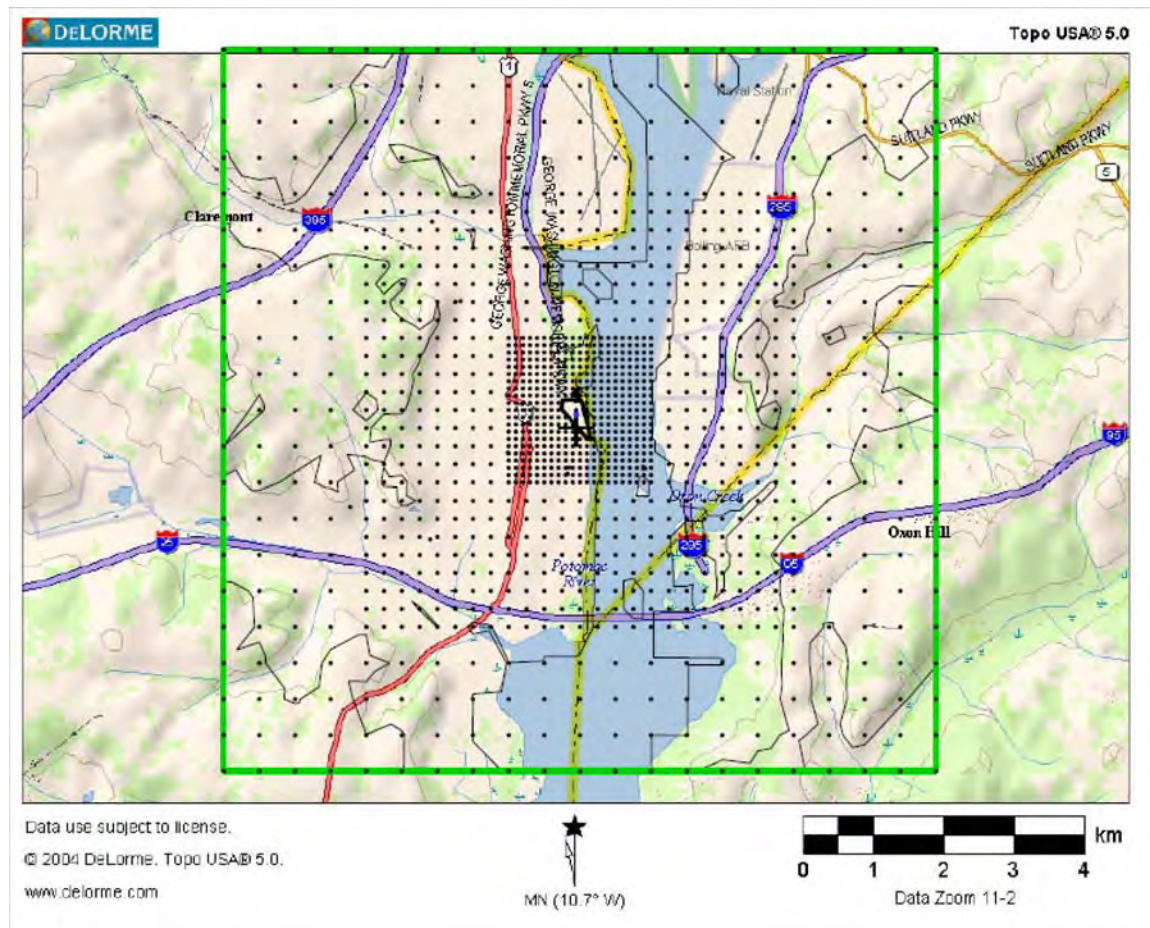


Figure 4.3.1-1. Map of receptor grid points for atmospheric dispersion modeling.

receptor grid forms a square 2,000 meters long on each side). A second set of receptors is located on the rectangular coordinates at 250-meter spacing for the distances between 1,000 and 3,000 meters of the Plant. Beyond 3,000 meters from the Plant, the receptor grid spacing is increased to 500-meter intervals. The receptor farthest from the Plant in an east-west direction (or in a north-south direction) is located 5,000 meters from the Plant. In addition to the grid of receptor locations, DOE modeled pollutant concentrations at several tall buildings in the vicinity of the Plant. DOE modeled 336 points around Marina Towers at the north end of the Plant, as well as points at multiple heights for six other nearby, tall buildings. The 336 points around Marina Towers are from 24 locations around the perimeter of the building and each of 24 floors of the building. Similarly, the multiple heights at the six other nearby buildings are the heights of each floor of the building.

AERMOD input data. For the period December 20, 2005, through March 31, 2006, DOE used actual unit-by-unit emissions (as provided by Mirant) and actual weather data obtained for Ronald Reagan Washington National Airport. These actual emissions and weather data were used in AERMOD to calculate local air pollution contributions of the Plant. For all other time periods DOE used estimated emissions and weather data from 2001 (as provided by EPA). Previous analyses by EPA had shown that 2001 resulted in predictions of more adverse air quality than the other years in the period 2000 through 2004.

For the period April 1 through May 31, 2006, DOE assumed that the Plant operated a different pair of units each week. Mirant reported to DOE that it had identified 10 two-unit operating modes (i.e., combinations of units that could operate for specified numbers of hours per day at specified SO₂ emission rates) that modeling by Mirant's contractor had demonstrated would not lead to exceedances of the 24-hour average SO₂ concentration at any location. For modeling purposes DOE assumed that the Plant practiced a ten-week rotation during which two of the five units were in operation during any given week. DOE assumed the following rotation of units: 1 and 2, 1 and 3, 1 and 4, 1 and 5, 2 and 3, 2 and 4, 2 and 5, 3 and 4, 3 and 5, and 4 and 5.

For the period April 1 through May 31, 2006, DOE assumed that the Plant operated a different pair of units each week. Mirant reported to DOE that it had identified 10 two-unit operating modes (i.e., combinations of units that could operate for specified numbers of hours per day at specified SO₂ emission rates) that modeling by Mirant's contractor had demonstrated would not lead to exceedances of the 24-hour average SO₂ concentration at any location. For modeling purposes DOE assumed that the Plant practiced a ten-week rotation during which two of the five units were in operation during any given week. DOE assumed the following rotation of units: 1 and 2, 1 and 3, 1 and 4, 1 and 5, 2 and 3, 2 and 4, 2 and 5, 3 and 4, 3 and 5, and 4 and 5.

For the month of June DOE assumed that two units at a time operated according to the schedule of allowed operations given in the ACO (Section 4.1.2). DOE assumed that the Plant used each of the 10 combinations of two units and operated each for three days.

DOE assumed that daily predictive modeling, as authorized by the ACO, was implemented beginning July 1, 2006. For operations under daily predictive modeling DOE assumed that, except during outages, each Plant unit generated power at the same level as it had during the year before Mirant terminated operations in August 2005¹⁷ and that at all times Mirant injected enough trona to achieve 50% SO₂ removal (i.e., controlled to 0.525 lb/MBtu). DOE estimated 50% SO₂ removal to be an average or typical removal rate. At low power generation times and/or favorable wind conditions, very little SO₂ removal is needed to meet air quality standards. During high generation times and/or unfavorable wind conditions, higher rates of trona use (to remove up to 80% of SO₂) are necessary to meet air quality standards. DOE selected the assumption of 50% removal as a mid-range value.

During the transmission line outages planned by Pepco (Table 1.3-1), DOE assumed that all five units operated as necessary to meet the full load of Central D.C. as determined from past data.¹⁸ DOE assumed that after a planned transmission outage the Plant resumed generating power at the level it had the year before operations were terminated on August 24, 2005.

The greatest modeled exceedances of the NAAQS SO₂ limits occur during line outage periods. Although removal of 80% of SO₂ from stack gases, which is technically feasible, would considerably reduce (but not eliminate) modeled exceedances, DOE's modeling of line outage periods assumes that the Plant removes 50% of SO₂ from stack gases. DOE has not modeled 80% removal because Mirant does not stockpile sufficient trona to maintain 80% SO₂ removal for an extended (typically, two-week) line outage.

Sulfur Dioxide. The SO₂ modeling proceeded by using AERMOD to calculate concentrations for each receptor grid point. To simulate the daily predictive modeling process of adjusting planned operations until modeled NAAQS compliance is achieved, DOE examined the 24-hour average concentration for each receptor grid point and for each day. For each day the predicted pollution concentration of each point in the receptor grid was reduced by the percentage that just brought the point with the highest concentration into compliance with the 24-hour SO₂ NAAQS limit.¹⁹ DOE performed this procedure for every modeled day (except

¹⁷ Mirant provided unit-by-unit, hour-by-hour generation data for the period September 1, 2004, through August 31, 2005. DOE used this hourly power generation data to represent what the Plant would do if there were no environmental constraints. Plant operations were terminated on August 24, 2005. Because the data suggest that the Plant started reducing operations on August 21, generation data after August 20 were not considered representative of normal operation.

¹⁸ During outages, DOE assumed that all five units operate at all times, each generating at least 30 MW (minimum capacity), for a total of at least 150 MW. When the load exceeded 150 MW but did not exceed 366 MW, DOE assumed that the two load-following or cycling units (Units 1 and 2) operated at minimum load (for a total of 60 MW) and the three baseload units (Units 3, 4, and 5) each operated at the same level to meet the remaining load. When the load exceeded 366 MW, DOE assumed that the baseload units each operated at capacity (102 MW), for a total of 306 MW, and the load-following or cycling units each operated at the same level to produce enough additional power to meet the demand until the load exceeded the capacity of the Plant (482 MW).

¹⁹ Compliance with the 24-hour SO₂ limit was based on a concentration of 314 µg/m³ (the NAAQS standard (continued...))

during outages) before calculating 3-hour, 24-hour, and long-term average concentrations. Although the ACO also requires modifying planned operations if daily predictive modeling forecasts an exceedance of 3-hour average SO₂ limits, DOE did not simulate predictive modeling for the 3-hour standard because the computational effort required to calculate average concentrations for all possible 3-hour periods for each of the 1,747 modeled locations was judged to be excessively large for the information to be gained.

Particulate Matter. DOE's modeling considered both stack emissions and fugitive emissions from the Plant as sources of airborne particulate matter.

Based on particulate emissions testing by TRC Environmental Corporation (2006), DOE used a stack emission rate of 0.019 lb PM₁₀ per MBtu when trona injection was employed and 0.035 lb/MBtu PM₁₀ when it was not in use. For operations before the Order and during the January 2006 transmission line outage, DOE assumed the 0.035 lb/MBtu PM₁₀ emission rate. For all other periods after the Order, DOE assumed the 0.019 lb/MBtu emission rate. DOE modeled stack emitted PM₁₀ emissions using the same operational schedule as used for SO₂ modeling. However, DOE did not simulate the effects of daily predictive modeling on PM₁₀ emissions because DOE found that with the 0.019 lb/MBtu emission rate, stack emissions never lead to exceedances of the NAAQS limit for PM₁₀.

DOE modeled fugitive PM₁₀ emissions using fugitive dust parameters supplied to EPA by Mirant. Some fugitive emissions are related to wind; for example, wind blows dust off the coal pile. Most of the emissions are related to the handling of coal and ash, which are operations that increase as plant operations increase. Fugitive dust modeling parameters were not, however, increased or decreased as generating levels increased or decreased. The parameters are based on the assumption that four of the five units operate full time, but they do not account for the extra dust generated by disposal of trona waste.

4.3.1.2 Uncertainties in modeling

The modeling results need to be interpreted cautiously because of many uncertainties related to assumptions and modeling approaches. Overall, DOE's approach was conservative in that it tends to overestimate impacts. Specific sources of uncertainty include the following:

1. DOE chose to use 2001 weather data because, based on EPA experience using 2000 through 2004 weather data, the 2001 data were more likely than other years to yield modeled exceedances.
2. For periods after June 30, 2006, DOE assumed that Mirant used trona injection to reduce SO₂ emissions by 50%. The Plant may operate with less than 50% SO₂ removal when

¹⁹ (...continued)
of 365 less the assumed background concentration of 51 µg/m³).

modeling (based on predicted weather conditions) does not indicate an exceedance would result. Conversely, the Plant may remove more than 50% of SO₂ or reduce power generation rates when modeling indicates this is necessary to avoid exceedances of the NAAQS. The assumption of 50% SO₂ removal is likely to mean that DOE's modeling underestimates the period-average concentrations of SO₂. However, because of the way DOE has modeled daily predictive modeling, this should introduce little error in estimates of maximum short-term SO₂ concentrations.

3. DOE did not model all of the operational possibilities available to Mirant. When modeling indicates an exceedance, DOE's modeling assumes that Mirant reduces emissions to a level just below what would cause a modeled exceedance. (This is equivalent to assuming that the power generation from each boiler is reduced by the necessary percentage, or that additional trona is injected at each boiler to reduce SO₂ emissions by that percentage.) While it is mathematically possible to exactly meet the 314-µg/m³ 24-hour limit, DOE expects Mirant to keep SO₂ emissions somewhat below the levels that are computed to just meet the limit. Therefore, this DOE modeling approach tends to overestimate actual 24-hour averages.²⁰
4. The ACO requires Mirant to achieve 80% SO₂ removal during line outage situations unless predictive modeling demonstrates that this level of SO₂ removal is not necessary or Mirant demonstrates that 80% removal is not "logistically feasible." Because Mirant does not have the capacity to stockpile sufficient trona for an extended line outage, DOE assumed 50% SO₂ removal during line outage situations.
5. DOE has used an estimate of fugitive PM₁₀ emissions that is based on the assumption that four of the five boiler units are operating at all times. While some fugitive emissions are caused by wind-blown erosion (e.g., of the coal pile), most fugitive emissions result from coal and ash handling. Because the amount of coal and ash handling is related to the level of power generation, fugitive emissions are probably overestimated for periods when the Plant is producing relatively little power. On the other hand, because the fugitive emissions rates do not account for increased emissions due to trona waste generated by operations, the fugitive emissions may be underestimated during high power generation periods.
6. DOE's modeling of operations under daily predictive modeling does not account for the use of monitoring and alarms to prevent exceedances of SO₂ NAAQS. The ACO requires

²⁰ Although not required, Mirant is known to be targeting 200 µg/m³ for a margin of predictive modeling to provide a margin of safety. (D. Lohman, EPA Region 3, personal communication with Seema Kakade, DOE, October 26, 2006.)

Mirant to monitor SO₂ at two locations on the top of Marina Towers and four other locations near the Plant. The ACO requires Mirant to maintain alarms that alert the Plant operators if monitored average concentrations reach 80% of the standards for SO₂. If one of the alarms sound, Mirant is required to modify operations to prevent an exceedance. (See Appendix B, Section IV, B, 5.) Because DOE's modeling does not account for use of monitoring to constrain operations, it overestimates the actual concentrations that will be observed during operations after this section of the ACO takes effect.

7. The highest modeled SO₂ concentrations occur at the rooftop at Marina Towers. Initial monitoring data collected by SO₂ monitors installed by Mirant for the MES do not show concentrations as high as calculated by Mirant's follow-up modeling, which is based on actual weather data. Because DOE believes it used the same AERMOD input parameters that Mirant used, these data suggest that the DOE application of AERMOD may overestimate maximum concentrations at Marina Towers. These data and the questions they raise are described in more detail in Section 4.3.1.4.

Despite the limitations, the results presented here are the best estimates available at this writing.

4.3.1.3 Modeling results for SO₂ and PM₁₀ emissions

The EPA has established air quality standards for different averaging periods. An area is considered to be in attainment when the standards are not exceeded at any location in the area. For most pollutants compliance is determined by the second highest value or some other statistical characteristic per year.

The tables in this section present concentrations for three time averaging periods: 3-hour, 24-hour, and specific indicated time periods ranging from 21 to 387 days in length, which are presented as surrogates for the annual average. Although the standards typically determine compliance by the second highest value or another statistical characteristic, for simplicity DOE presents only the highest value for the specified averaging period. This maximum value is likely to be higher than the value used to determine compliance with the standard.

In all cases the value presented in the table is the modeled value for the receptor location that had the highest modeled value among the 1,747 modeled receptor locations. The 3-hour average refers to the highest average concentration for any three consecutive hours for any location. The 24-hour average is the highest average concentration for any calendar day (in the period) at any location. The maximum 3- and 24-hour averages represent relatively unusual occurrences. The annual or period average is more indicative of the usual air quality. Because most of the modeled periods are shorter than one year, the modeled period averages in the tables are not directly comparable to the annual air quality standards, but they do indicate how the period contributes to the annual average. For example, operations during a period with an average that exceeds the annual standard could contribute toward an exceedance of the annual

standard, while operations during a period with an average below the standard could contribute toward meeting the annual standard. Note that, because pollutants are not evenly distributed across the area, all values in the tables considerably overstate the expected concentration at all but a few of the 1,747 modeled locations.

Table 4.3.1-1 shows modeled SO₂ and PM₁₀ concentrations for pre-shutdown operations, pre-Order operations, and operations under the Order through September 30, 2006. The first row of the table presents maximum background concentrations. These are the maximum values observed at nearby ambient air quality monitoring stations for the specified averaging periods (Table 3.1-2). The ACO specifies that these “background concentrations” must be added to modeled concentrations resulting from Plant operations in determining whether a “modeled exceedance” occurs. Other rows in the table present modeled concentrations resulting from Plant operations and summed values in which modeled concentrations are added to the maximum background concentrations. The summation approach specified in the ACO is conservative because it is very unlikely that maximum Plant-induced concentrations would occur at the same time as maximum background concentrations. The modeling results presented in the table are discussed in more detail in the following paragraphs.

Pre-shutdown operations. Until August 2005 the Plant operated in the historical manner; essentially, it produced power as economics would dictate. The Plant operated without controls on SO₂ emissions. Table 4.3.1-1 shows that modeling of pre-shutdown operations predicts significant exceedances of the NAAQS for SO₂ concentrations. The table also shows exceedance for the maximum 24-hour PM₁₀ concentration. The maximum PM₁₀ values reported here are dominated by fugitive dust emissions. Maximum modeled concentrations of PM₁₀ from stack emissions are generally less than half of concentrations due to fugitive emissions.

Pre-Order operations. During the fall of 2005, the Plant operated in an 8-8-8 mode: 8 hours off, 8 hours at minimum power, and 8 hours at up to maximum power each day (Section 4.2.2). During this period the Plant was experimenting with trona injection and use of Colombian coal. However, Mirant had performed modeling that showed that no exceedance of the NAAQS SO₂ limit would occur under 8-8-8 operation even if no SO₂ control were employed. Consequently, during this period Mirant did not control SO₂ emissions to any set level. Table 4.3.1-1 shows the results of modeling pre-Order operations for an assumed full year. The table shows that pre-Order operations allow the Plant to meet SO₂ limits.

During 2005 and 2006, Mirant implemented several fugitive dust control measures (Section 2.5). Modeling of PM₁₀ concentrations resulting from pre-Order operations used emissions factors that assume that some of these measures were in place. Table 4.3.1-1 shows that modeled PM₁₀ concentrations for pre-Order operations are substantially lower than for pre-shutdown operations and meet the PM₁₀ limits.

**Table 4.3.1-1. Modeled maximum ambient SO₂ and PM₁₀ concentrations (µg/m³)
for Plant operations among all receptor locations.**

Operating Scenario and Period	SO ₂			PM ₁₀	
	Maximum 3-hour average	Maximum 24-hour average	Maximum period average (for the specified period or 1 year)	Maximum 24-hour average	Maximum period average (for the specified period or 1 year)
Maximum Background Concentration	238 ^a	51 ^a	16 ^a	45 ^a	21 ^a
Modeled Maximum Concentrations					
Pre-shutdown operations (Sep. 1, 2004 through Aug. 20, 2005)	5,156	2,967	299	150	25
Pre-Order operations (annual)	767	277	24	61	13
Dec. 20, 2005 through June 30, 2006					
Non-outage periods (172 days)	479	246	32	36	9
Outage periods (21 days)	3,484	1,888	389	43	13
July 1 through September 30, 2006	1,445	314	136	58	10
Modeled Maximum Concentrations with Maximum Background Concentrations Added					
Pre-shutdown operations (Sep. 1, 2004 through Aug. 20, 2005)	5,394	3,018	315	195	46
Pre-Order operations (annual)	1,005	328	40	106	34
Dec. 20, 2005 through June 30, 2006					
Non-outage periods (172 days)	717	295	48	81	30
Outage periods (21 days)	3,772	1,939	405	88	34
July 1 through September 30, 2006	1,683	365	152	103	31
NAAQS limit^b	1,300	365	80	150	50

Note: Modeled values are the highest criteria pollutant concentration among all receptor locations. Pre-shutdown and pre-Order operations do not include higher levels of operations for line outages. Actual or planned line outage conditions are included in the operational periods of the Order. Annual values for modeled concentrations for periods less than one year are time-weighted averages. Whereas many NAAQS limits are specified as the second highest or other value, the modeled values presented in this table are the highest values.

^a These are the highest values observed at nearby monitoring stations for the specified averaging periods. At most times ambient concentrations are lower than these values. Annual SO₂ concentration is the annual arithmetic mean for years 2001, 2002, and 2003 measured at 517 N. Saint Asaph Street, Alexandria City (ENSR Corporation 2005). Annual PM₁₀ concentration is the 2004 arithmetic mean reported in VDEQ 2005, page 49, monitoring site L-46-B3. (Just before publication of this document, Virginia released ambient air monitoring data for 2005 [VDEQ 2006c]. The updated background levels vary only slightly from the 2004 values reported and used here.)

^b NAAQS values from 40 CFR Part 50. See Section 3.1.2 and Table 3.1-1 for an explanation of NAAQS and the averaging periods that apply to each. EPA's October 17, 2006, rule making on NAAQS for particulate matter (EPA 2006j) revoked the annual PM₁₀ standard, effective December 18, 2006.

Operations under the Order. Operations under the Order were addressed in two periods, December 20, 2005, through June 30, 2006, and July 1 through September 30, 2006. Operations under the Order were divided in this manner because DOE assumed that operations changed significantly when Mirant began operations under daily predictive modeling as permitted by the ACO. The following paragraphs discuss the effects of SO₂ and PM₁₀ emissions for these two time periods.

December 20, 2005, through June 30, 2006. For the December through June period, maximum modeled SO₂ concentrations (Table 4.3.1-1) show exceedances of the SO₂ limits during the January line outages, when the highest modeled 3- and 24-hour SO₂ concentrations occurred. For most of the outage trona injection was available on only one unit; Mirant injected trona in two units simultaneously during the last week of the outage. For non-line outage periods through June 30, there were no modeled exceedances of the 3- or 24-hour limits, in part because the Plant operated at a relatively low average power. Table 4.3.1-1 shows no modeled exceedances of limits for PM₁₀ during either line outage or non-line outage periods. The fugitive dust parameters used in modeling PM₁₀ concentrations for this time period reflect the progressive implementation of fugitive dust control measures at the Plant.

July 1 through September 30, 2006. The commencement of *daily predictive modeling* on July 1, 2006, approximately coincided with the beginning of the season of highest power demand (Figure 4.2-1). Beginning July 1, 2006, modeled plant generation increased and modeled SO₂ exceedances occur for all averaging periods except the 24-hour average during non-outage periods. The ACO requires modifying planned operations if daily predictive modeling forecasts an exceedance of either 3- or 24-hour average SO₂ limits. DOE's modeling assumed that the Plant would scale back operations to meet the 24-hour SO₂ standard as required by the ACO (Section 4.1.2). However, as described in Section 4.3.1.1, DOE's model did not assume that the Plant would scale back operation to meet the 3-hour standard, even though it is required by the ACO, because it would have been excessively complex to model. In actuality, it is expected that the modeled maximum 3-hour average exceedances indicated by Table 4.3.1-1 for the July through September period would be prevented by daily predictive modeling. However, the model's prediction of exceedances when the 3-hour limit is not applied suggests that controlling operations for 24-hour averages is not enough to assure compliance with the 3-hour average SO₂ limit.

The modeled exceedance of the longer-period average SO₂ limit (Table 4.3.1-1) is a logical consequence of operations under daily predictive modeling, because daily predictive modeling allows the Plant to operate at the highest levels that do not cause exceedances of 24-hour SO₂ limit. Operating close to the 24-hour limit (314 g/m³) day after day inevitably raises the long-term average to a higher level than for a plant that does not consistently operate close to the limit.

The exceedances indicated in the table are modeled exceedances, not actual exceedances. The ACO has provisions for preventing actual exceedances during non-outage periods. In particular, the ACO requires Mirant to monitor SO₂ concentrations near the top of Marina Towers (where the maximum modeled exceedances occur) for close approaches to NAAQS SO₂ limits. If a monitored concentration exceeds 80% of the limit for one of the averaging periods, an audible alarm will sound in the control room (Section 4.1.2.1) and the ACO requires Mirant to take corrective action, such as reducing power generation. Consequently, DOE anticipates that actual exceedances of the SO₂ limits will not occur during non-line outage periods.

As shown by Table 4.3.1-1, Plant operations under the ACO do not result in modeled exceedances of any of the NAAQS limits for PM₁₀.

Operations during a potential extension of the Order until new transmission lines are installed. Table 4.3.1-2 presents modeled maximum concentrations of SO₂ and PM₁₀ due to Plant operations during a potential 9- or 15-month extension of the Order beyond September 30, 2006. This includes the period of the temporary 2-month extension of the Order from October 1 to December 1, 2006. Pepco's current schedule has the new transmission lines being installed and operational by the end of June 2007. Because there is a possibility that the transmission lines may not become operational on schedule, DOE has also examined a scenario for extension of the Order through December 2007.

As shown by Table 4.3.1-2, compliance with the ACO leads to meeting the NAAQS limits for 24-hour average SO₂ concentrations during non-line outage periods. As with operations under the initial term of the Order, DOE's model did not assume that the Plant would scale back operation to meet the 3-hour standard as required by the ACO. In actuality, it is expected that the modeled maximum 3-hour average exceedances indicated by Table 4.3.1-2 would be prevented by daily predictive modeling. The modeled exceedances of the NAAQS SO₂ limits for the annual average during non-line outage situations shown in Table 4.3.1-2 result from the assumption that the Plant operates close to the 24-hour limit on a continuing basis. Under the ACO Mirant would be required to modify Plant operations to avoid predicted exceedances of all SO₂ NAAQS averaging periods. Consequently, DOE anticipates that actual exceedances of the SO₂ limits would not occur during non-line outage periods.

As shown by Table 4.3.1-2, Plant operations under an extension of the Order would not result in modeled exceedances of any of the NAAQS limits for PM₁₀.

EPA has provided DOE with preliminary data on monitored air quality measurements taken by Mirant pursuant to the ACO. Mirant sent this information to EPA as part of its monthly reporting requirements under the ACO. EPA is currently reviewing and interpreting the data; however, as discussed in Section 4.3.1.4, the data suggest that actual air quality impacts from operation of the Plant under daily predictive modeling are lower than impacts predicted through DOE's modeling efforts.

4.3.1.4 Monitored SO₂ data

Pursuant to the requirements for performing the MES (Appendix B, Section VI), Mirant has installed six SO₂ monitoring stations near the Plant. Two are located on the roof of Marina Towers--one at the center of the building and one on the southeast wing. One station is located east of stack 5 on the west bank of the Potomac River. Another monitor is located southeast of the Plant along the fence line near the River. One monitor is located at Daingerfield Island about 800 m north of Marina Towers. One monitor is located on the roof of Harbor Terrace (Holiday Inn) southwest of the Plant. These monitoring sites were selected based on discussions among Mirant, DOE and EPA modeling and meteorological experts.

Initial results from the monitors show that actual monitored daily average (approximately the same as 24-hour average) values are much lower than shown by Mirant's follow-up modeling using actual hourly emissions and exhaust parameters and observed weather

Table 4.3.1-2. Modeled maximum ambient SO₂ and PM₁₀ concentrations (µg/m³) for Plant operations among all receptor locations for a potential extension of the Order.

Operating Scenario and Period	SO ₂			PM ₁₀	
	Maximum 3-hour average	Maximum 24-hour average	Maximum period average (for the specified period or 1 year)	Maximum 24-hour average	Maximum period average (for the specified period or 1 year)
Maximum Background Concentration	238 ^a	51 ^a	16 ^a	45 ^a	21 ^a
Modeled Maximum Concentrations					
Potential extension of the Order Oct. 1, 2006 – Jun. 30, 2007					
Non-outage periods (203 days)	1,236	314	101	61	12
Outage periods (70 days)	2,193	1,152	171	66	13
Potential extension of the Order Oct. 1, 2006 – Dec. 31, 2007					
Non-outage periods (387 days)	1,449	314	115	67	12
Outage periods (70 days)	2,193	1,152	171	66	13
Modeled Maximum Concentrations with Maximum Background Concentrations Added					
Potential extension of the Order Oct. 1, 2006 – Jun. 30, 2007					
Non-outage periods (203 days)	1,474	365	117	106	33
Outage periods (70 days)	2,431	1,203	187	111	34
Potential extension of the Order Oct. 1, 2006 – Dec. 31, 2007					
Non-outage periods (387 days)	1,687	365	131	112	33
Outage periods (70 days)	2,431	1,203	187	111	34
NAAQS limit^b	1,300	365	80	150	50

Note: All periods include the period of the two-month temporary extension of the Order from October 1 to December 1, 2006. Modeled values are the highest criteria pollutant concentration among all receptor locations. Planned transmission line outages in preparation for the 230-kV lines are included in the periods. Annual values for modeled concentrations for periods other than one year are time-weighted averages. While, many NAAQS limits are specified as the second highest or other value, the values presented in this table are the highest values.

^a These are the highest values observed at nearby monitoring stations for the specified averaging periods. At most times, ambient concentrations are lower than these values. Annual SO₂ concentration is the annual arithmetic mean for years 2001, 2002, and 2003 measured at 517 N. Saint Asaph Street, Alexandria City (ENSR Corporation 2005). Annual PM₁₀ concentration is the 2004 arithmetic mean reported in VDEQ 2005, page 49, monitoring site L-46-B3. (Just before publication of this document, Virginia released ambient air monitoring data for 2005 [VDEQ 2006c]. The updated background levels vary only slightly from the 2004 values reported and used here.)

^b NAAQS values from 40 CFR Part 50. See Section 3.1.2 and Table 3.1-1 for an explanation of NAAQS and the averaging periods that apply to each. EPA's October 17, 2006, rule making on NAAQS for particulate matter (EPA 2006j) revoked the annual PM₁₀ standard, effective December 18, 2006.

conditions, matched hour for hour. Specifically, for the period June 17 through September 17, 2006, the maximum monitored daily-average concentration for the monitors ranged from 4 to 63 µg/m³. For the same time period Mirant's follow-up modeling of actual operations using weather data recorded at Ronald Reagan Washington National Airport gave maximum daily-average concentrations that ranged from 25 to 570 µg/m³. Aside from the specific operations and weather data, follow-up modeling used the same parameters to characterize the Plant as used for the analysis in the SEA and the 2005 downwash study (ENSR Corporation 2005).

The reasons for the discrepancy between monitored and maximum concentrations from follow-up modeling are not apparent. Mirant's technical consultant reports that when modeling uses effective building dimensions derived from a wind tunnel study, the resulting modeled maximum SO₂ concentrations are closer to the monitored concentrations (Personal communication between D. Shea, ENSR Corporation, Welsford, MA, and L.N. McCold, Oak Ridge National Laboratory, Oak Ridge, TN, October 3, 2006), but this modeling approach does not fully account for the discrepancy. An explanation suggested by Mirant's consultant is that AERMOD underestimates the buoyancy of multiple stack plumes when the wind is blowing parallel to the line of stacks. Another possible explanation is that the weather data from National Airport does not precisely match the weather at the Plant. Mirant's consultant reports that wind directions reported at National Airport are often slightly different from those detected at the Plant. Particularly near the Plant, small differences in wind direction can cause large differences in pollutant concentration at any specific point.

The discrepancy between monitoring data and modeled concentrations raises the possibility that the modeled maximum concentrations reported in Tables 4.3.1-1 and 4.3.1-2 of this SEA are unrealistically high for receptor points that are very close to the Plant. However, because DOE used forecasts rather than actual emissions and weather data, the results presented in this SEA are not directly comparable to either the monitoring data or to Mirant's follow-up modeling.

Because the MES may require as much as a year of monitoring data, EPA is not expected to reach a conclusion about the accuracy of the modeled concentrations before late 2007. In the meanwhile, the ACO requires that the Plant be operated to avoid predicted modeled exceedances.

4.3.1.5 Other air pollutants

Contributions to PM_{2.5} pollution. For PM_{2.5} the NAAQS specify a maximum annual average concentration of 15 µg/m³ and a 98th-percentile 24-hour average concentration of 65 µg/m³. Regulation of PM_{2.5} is still developing. On October 17, 2006, EPA published new ambient air quality standards for PM_{2.5} in the *Federal Register* (EPA 2006j). The new standards, which take effect December 18, 2006, retain the level of 15 µg/m³ for the annual average and institute a 35 µg/m³ 24-hour average. State implementation plans (SIPs) for PM_{2.5} are not due to EPA until 2008.

The PM_{2.5} monitor nearest to the Plant is at Aurora Hills Visitor Center (Table 3.1-2), a short distance west of Ronald Reagan Washington National Airport. The 2004 annual average PM_{2.5} concentration measured at Aurora Hills was 14.4 µg/m³; the 98th-percentile 24-hour average concentration was 35.7 µg/m³.²¹ As noted in Section 3.1.2, the region in which the Plant exists is in nonattainment with the PM_{2.5} standard.

²¹ Just before publication of this document, Virginia released ambient air monitoring data for 2005 (VDEQ 2006c). The updated background levels vary only slightly from the 2004 values reported and used here.

There are two important sources of particulate matter associated with the Plant: stack emissions and fugitive dust. Because fugitive dust from the Plant is emitted near ground level, for locations near the Plant fugitive dust is the principal source of ground level PM_{2.5} attributable to Plant operations. Because stack emissions are located far off the ground, they are the most important Plant-related source of particulate matter at nearby elevated receptor locations, specifically near the top of Marina Towers. Because both ground level and elevated concentrations are important, maximum values for each are presented here.²²

DOE used estimates of PM₁₀ concentrations (Section 4.3.1.3) as a basis for estimating PM_{2.5} concentrations. EPA's AP-42 emission factor guidelines (Personal communication between D. Lohman, U.S. EPA, Region III, and L.N. McCold, Oak Ridge National Laboratory, August 28, 2006) applied to wind blown dust indicate that PM_{2.5} is 15% of the PM₁₀. Based on this guidance, DOE assumed that 15% of fugitive PM₁₀ was PM_{2.5}. The AP-42 factors for the PM_{2.5} fraction of PM₁₀ from electric generating units controlled by electrostatic precipitators range between 44% for dry bottom boilers and 76% for over-fire stokers (Personal communication between D. Lohman, U.S. EPA, Region III, and L.N. McCold, Oak Ridge National Laboratory, August 28, 2006). Based on this guidance, DOE conservatively assumed 76% of PM₁₀ emitted from the Plant stacks was PM_{2.5}.

DOE's analysis considers only directly emitted particulate matter. In addition to PM_{2.5} that is emitted directly as particulate matter, certain chemicals, especially SO₂ and NO_x, are emitted as gases, but form particulate matter after they are released. This source of PM_{2.5} is not included in the air quality analysis because AERMOD does not incorporate a photochemical model that can account for nonlinear chemical reactions. In addition, such a model would require much more extensive atmospheric data than are readily available. However, because the background concentrations used in developing DOE's PM_{2.5} estimates were measured while the Plant was operating at pre-shutdown levels, some, unknown but probably small, fraction of the background is due to Plant operations. Consequently, adding estimated Plant contributions to background concentrations involves some double counting of Plant effects. The discussion below presents estimates of PM_{2.5} contributions first with and then without background concentrations.

Pre-shutdown operations. Pre-shutdown operations (one year) are estimated to have resulted in maximum 24-hour average concentrations of 74 µg/m³ (38 µg/m³ due to Plant operations alone; that is, without background) at ground level and 112 µg/m³ (76 µg/m³ due to Plant operations) at the top of Marina Towers. The annual average ground level PM_{2.5} concentration was estimated to be 20 µg/m³ (5.7 µg/m³ due to Plant operations), and the average annual PM_{2.5} concentration at the top of Marina Towers was estimated to be 22 µg/m³ (7.8 µg/m³ due to Plant operations).

Pre-Order operations. If pre-Order operations had continued for one year, the maximum estimated ground-level 24-hour-average PM_{2.5} would have been 45 µg/m³ (9.2 µg/m³ due to

²² Both stack and fugitive sources were included in estimating PM_{2.5} concentrations for both ground-level and elevated receptors.

Plant operations), and the comparable concentration at the top of Marina Towers would have been $40 \mu\text{g}/\text{m}^3$ ($4.8 \mu\text{g}/\text{m}^3$ due to Plant operations). The maximum estimated ground-level annual average $\text{PM}_{2.5}$ concentration would have been $16 \mu\text{g}/\text{m}^3$ ($2.0 \mu\text{g}/\text{m}^3$ due to Plant operations), and the maximum annual average concentration at the top of Marina Towers would have been $15 \mu\text{g}/\text{m}^3$ ($1.0 \mu\text{g}/\text{m}^3$ due to Plant operations).

Operations under the Order. For the duration of the Order, the estimated maximum 24-hour-average ground-level $\text{PM}_{2.5}$ concentration is $61 \mu\text{g}/\text{m}^3$ ($25 \mu\text{g}/\text{m}^3$ due to Plant operations), and the maximum estimated ground-level 285-day-period-average $\text{PM}_{2.5}$ concentration is $38 \mu\text{g}/\text{m}^3$ ($2.4 \mu\text{g}/\text{m}^3$ due to Plant operations). Because an important fugitive dust suppression measure was implemented in March 2006, the period before April contributed more to the 285-day-period average $\text{PM}_{2.5}$ concentration than operations after April, and the maximum estimated 24-hour-average $\text{PM}_{2.5}$ concentration occurred before April.

For the duration of the Order, the maximum 24-hour-average concentration at the top of Marina Towers is $76 \mu\text{g}/\text{m}^3$ ($41 \mu\text{g}/\text{m}^3$ due to Plant operations), and the maximum 285-day-period-average concentration at the top of Marina Towers is $18 \mu\text{g}/\text{m}^3$ ($3.9 \mu\text{g}/\text{m}^3$ due to Plant operations). Because of increased generation after the start of operations under daily predictive modeling, operations after June contributed more to the 285-day-period-average $\text{PM}_{2.5}$ concentrations than operations before July, and the maximum estimated 24-hour-average concentration occurred after June.

Potential extension of the Order. For a potential extension of the Order through December 2007 (including the period of the temporary extension until December 1, 2006), the estimated maximum 24-hour average ground-level concentration would be $58 \mu\text{g}/\text{m}^3$ ($23 \mu\text{g}/\text{m}^3$ due to Plant operations), and the maximum estimated concentration on the top of Marina Towers would be $79 \mu\text{g}/\text{m}^3$ ($43 \mu\text{g}/\text{m}^3$ due to Plant operations). The estimated maximum 24-hour average occurs during non-outage periods. The estimated maximum annual average ground-level $\text{PM}_{2.5}$ concentration would be $18 \mu\text{g}/\text{m}^3$ ($4.0 \mu\text{g}/\text{m}^3$ due to Plant operations), and the estimated maximum concentration at the top of Marina Towers would be $20 \mu\text{g}/\text{m}^3$ ($5.7 \mu\text{g}/\text{m}^3$ due to Plant operations).

Nitrogen oxide contributions to ozone (O_3) pollution. Alexandria and the surrounding area are in nonattainment for O_3 . Ozone is formed in the atmosphere when sunlight interacts with NO_x and volatile hydrocarbons. In the eastern United States, natural volatile hydrocarbon molecules are abundant in the atmosphere. Consequently, the most effective method for limiting the formation of O_3 is limiting the abundance of NO_x in the atmosphere. NO_x is readily formed in high temperature combustion processes such as power plants and internal combustion engines.

The following data were used to estimate NO_x emissions. Hourly operations data for December 20, 2005, through March 31, 2006, indicate that average NO_x emission rate for Units 1 and 2 is about 0.35 lb/MBtu and the emission rate for Units 3, 4, and 5 averages 0.26 lb/MBtu. Assuming that each unit consumes the same average amount of coal, the average emission rate would be 0.296 lb per MBtu of coal consumed. At 12,000 Btu/lb of coal, Units 1 and 2 have NO_x

emission rates of 8.4 lb per ton of coal. When all units operate (using equal quantities of coal), the average NO_x emission rate is about 7.1 lb per ton of coal.

As a point of reference, the ACO requires that the Plant emit no more than 3,700 tons (3,400 metric tons) of NO_x per year.

Pre-shutdown operations consumed about 832,000 tons (755,000 metric tons) of coal per year and emitted 3,000 tons (2,700 metric tons) of NO_x per year. For comparison purposes, if pre-shutdown operations had continued for the 285-day duration of the Order, the Plant would have consumed about 650,000 tons (590,000 metric tons) of coal and emitted about 2,300 tons (2,100 metric tons) of NO_x. If pre-shutdown operations were to continue for a 15-month extension of the Order through December 2007 (including the period of the temporary extension until December 1, 2006), the Plant would consume about 1,040,000 tons (943,000 metric tons) of coal and emit about 3,700 tons (3,400 metric tons) of NO_x.

Pre-Order operations. For comparison purposes, if pre-Order operations (when only Unit 1 operated) had continued for the duration of the Order, the Plant would have consumed about 153,000 tons (140,000 metric tons) of coal and emitted about 640 tons (580 metric tons) of NO_x, a rate of about 820 tons (750 metric tons) per year. If pre-Order operations were to continue for an extension of the Order through December 2007 (including the period of the temporary extension until December 1, 2006), the Plant would emit about 1,030 tons (940 metric tons) of NO_x over the 15-month period.

For the 285-day term of *the Order*, the Plant is estimated to burn about 566,000 tons (504,000 metric tons) of coal and emit about 2,600 tons (2,300 metric tons) of NO_x, a rate of 2,600 tons (2,300 metric tons) per year.

For *potential extension of the Order* from October 1, 2006 through December 2007 (including the period of the two-month temporary extension until December 1, 2006), the Plant would consume about 1,040,000 tons (940,000 metric tons) of coal and emit about 3,700 tons (3,400 metric tons) of NO_x, a rate of about 3,000 tons (2,700 metric tons) per year.

Contributions to carbon monoxide (CO) and lead pollution. As shown by Table 3.1.2, monitored levels of CO are well below the standard. Because CO levels are so low and because coal-fired power plants are not significant sources of CO, DOE did not model contributions to ambient CO levels due to Plant operations. Because ambient lead concentrations have declined to such low levels since the elimination of leaded gasoline that lead concentrations are no longer monitored in Virginia, DOE did not model potential contributions due to Plant operations.

Contributions to hazardous air pollutants. *Mercury* emissions by coal fired power plants are believed to be a major contributor to atmospheric mercury contamination. In its elemental form mercury is easily vaporized. Mercury forms nonvolatile compounds with sulfur and chlorine that can be captured in precipitators and incorporated in fly ash, but DOE assumed that all mercury in the coal burned by the Plant is emitted to the atmosphere through the stacks. This assumption is not likely to lead to an overestimate of mercury emissions because chemical analyses of Plant fly ash did not detect mercury (Section 4.3.5).

Data provided by Mirant indicates that the mercury content of coal supplied to the Plant ranges from 0.03 to 0.07 ppm (0.06 to 0.14 lb mercury per thousand tons of coal). DOE's analysis conservatively uses the high end of this range, that is 0.14 lb per thousand tons of coal.

Pre-shutdown operations consumed about 832,000 tons (755,000 metric tons) of coal per year. At 0.14 lb of mercury per thousand tons of coal, pre-shutdown operations can be estimated to emit 116 lb/year (53 kg/year) of mercury. For the 285-day period of the Order, it would emit about 91 lb of mercury. For extension of pre-shutdown operations through a 15-month extension of the Order, operations would emit about 145 lb of mercury.

For *pre-Order operations*, the Plant would burn about 540 tons (490 metric tons) of coal per day. Pre-Order operations for the period of the Order would lead to consumption of about 153,000 tons (140,000 metric tons) of coal. At 0.14 lb mercury per thousand tons of coal, pre-Order operations would have caused emission of about 21 lb (10 kg) of mercury for the period of the Order. Pre-Order operations for a 15 month extension of the Order would involve consumption of about 245,000 tons (220,000 metric tons) of coal and emission of about 34 lb (16 kg) of mercury.

For the 285 days of *the Order*, DOE estimates Plant coal consumption at 566,000 tons (510,000 metric tons), resulting in emissions of about 79 lb (36 kg) of mercury. Thus, the Order is estimated to increase mercury emissions of the Plant by 58 lb (26 kg) over the 285-day term of the Order. By comparison, if *pre-shutdown operations* had continued for the same 285 days, the Plant would have consumed about 650,000 tons (590,000 metric tons) of coal and emitted about 91 lb (41 kg) of mercury.

For *potential extension of the Order* from October 2006 through December 2007 (including the period of the two-month temporary extension until December 1, 2006), the Plant would consume about 1,040,000 tons (943,000 metric tons) of coal and emit approximately 146 lb (66 kg) of mercury. By comparison, pre-Order operations of the Plant for the same period would involve burning about 245,000 tons (220,000 metric tons) of coal with emission of about 34 lb (16 kg) of mercury. Thus, extension of the Order for 15 months would result in an increase in mercury emissions, over pre-Order operations, of about 111 lb (50 kg) mercury.

Other metals typically present as trace constituents of coal are less volatile than mercury, so they are primarily incorporated into solid wastes (bottom ash and fly ash), with only small fractions emitted to the atmosphere. The coal data that Mirant provided to DOE did not include concentrations of toxic metals other than mercury. Table 2.3-1 summarizes some published data on concentrations of seven trace metals in Appalachian coals. These data provide an indication of levels that may be present in the central Appalachian coal burned by the Plant. DOE performed a mass balance analysis for five of these metals using data on fly ash from Table 4.3.5-2. The results suggest that much of the arsenic and cadmium in the original coal, and some of the lead, selenium, and chromium are captured in fly ash. Capture of selenium in fly ash increases greatly when trona is used in the Plant (Section 4.3.5). DOE does not have data on the composition of the Plant's bottom ash, which would be expected to contain the majority of some metals, particularly the least volatile, such as beryllium, chromium, and nickel. Metals not

captured in a solid phase are released to the atmosphere. DOE has not estimated the quantities of these metals released to the atmosphere.

4.3.1.6 General conformity requirement

Background. General conformity arises out of Section 176(c)(1) of the Clean Air Act (CAA) which provides that no Federal agency shall “engage in, support in any way or provide financial assistance for, license or permit, or approve, any activity which does not conform to [an approved State implementation plan (SIP)].” Under the CAA conformity to an implementation plan means that such activities will not (1) cause or contribute to any new violation of any standard in any area, (2) increase the frequency or severity of any existing violation of any standard in any area, or (3) delay timely attainment of any standard or any required interim emission reductions or other milestones in any area [CAA §176(c)(1)(B)].

Before DOE issued its Order, VDEQ raised several concerns related to general conformity in its filing to FERC (VDEQ 2005b).²³ VDEQ claimed that resumption of Plant operations at the previous levels would “not be in conformity with the Virginia SIP’s purpose of eliminating or reducing the severity and number of exceedances of the NAAQS.” VDEQ’s filing to FERC also claimed that resumption of Plant operations “at the previous levels, or any other level that would not be protective of human health or the environment, would clearly conflict with Mirant’s regulatory obligation to comply with the [VDEQ] Director’s request under 9 VAC 5-20-180(I), and therefore would not be in conformity with the SIP.”

The Federal general conformity regulations implementing Section 176(c)(1) of the CAA are codified at 40 CFR Part 51, Subpart W, and 40 CFR Part 93, Subpart B. Pursuant to 40 CFR 51.851, Virginia has an EPA approved general conformity rule that complies with the CAA. Therefore, Virginia’s general conformity rule applies here.

Under the general conformity rules, if the conformity rule applies to a Federal action, then the agency must determine whether the action “conforms” to a SIP. The conformity rule applies for each pollutant where the total of direct and indirect emissions in a nonattainment or maintenance area caused by the action would equal or exceed de minimis thresholds and where the action does not fit an exception (9 VAC 5-160-30). If the conformity rule applies, a Federal action is deemed to “conform” to a SIP if it is in compliance with all relevant requirements and milestones in the SIP and meets one of several requirements enumerated in the regulations, such as the emissions are specifically identified and accounted for in the SIP (40 CFR 93.158, 9 VAC 5-160-160).

The city of Alexandria and surrounding Arlington, Fairfax, Loudoun, and Prince William counties are in nonattainment for PM_{2.5} and 8-hour ozone (the precursors for ozone are NO_x and volatile hydrocarbons) (EPA 2006f). Because the general conformity regulations only apply to

²³ As stated in DOE’s Order (footnote 2), DOE considered all legal arguments made in FERC filings in its decision-making process.

Federal actions that exceed de minimis thresholds in designated “nonattainment” or “maintenance” areas, these are the only pollutants that are relevant here.

The Order conforms to the Virginia SIP. Because the Order does not cause or contribute to new emissions not already accounted for in the SIP or interfere with limits in the SIP, the Order conforms to the Virginia SIP. The Order does not allow the Plant to resume operations at levels it had been operating at under the Virginia SIP before the August 24, 2005, shutdown. Instead, the Order only allows the Plant to operate at pre-shutdown levels in limited transmission line outage circumstances, or when permitted by daily predictive modeling. In addition, for PM_{2.5} the Order cannot interfere with PM_{2.5} emissions not already accounted for in the SIP because Virginia does not currently have a SIP for PM_{2.5}.²⁴ Similarly, because the original study regarding the Plant’s NO_x emissions (prompting the shutdown of the Plant on August 24, 2005), related to downwash rather than to NO_x as a precursor to ozone, the Order would not appear to affect Virginia’s SIP for ozone (EPA 2006g).²⁵

Furthermore, the Order alleviates the concerns related to conformity to the SIP raised by VDEQ in its filing to FERC. To the extent that the SIP accounts for full operation of the Plant without the use of trona and low-sulfur coal, the Order actually decreases emissions already accounted for in the SIP. Therefore, the Order helps Virginia achieve its “purpose of eliminating or reducing the severity and number of exceedances of the NAAQS” (VDEQ 2005b). The Order also does not present a conflict between resumption of Plant operations under the Order and Mirant’s regulatory obligation to comply with the VDEQ Director’s August 19, 2005, request. Indeed, the VDEQ Director’s August 19, 2005, letter to Mirant suggested the “potential reduction of levels of operation” as a potential method of complying with the Director’s request under 9 VAC 5-20-180(I) to “immediately undertake such action as is necessary to ensure protection of human health and the environment” (Personal communication between R.G. Burnley, VDEQ, and L.D. Johnson, Mirant Potomac River, LLC., August 19, 2005). Moreover, the DOE Order does not impinge upon VDEQ’s ability to enforce concerns over pollutants emitted from the Plant. For example, during the period of the Order, VDEQ continued to work with EPA and Mirant on a long-standing settlement over NO_x that began in 2003 and resulted in an amended settlement on May 8, 2006 (EPA 2006g).

The function of the general conformity requirement is to ensure that Federal actions do not interfere with SIPs for meeting CAA standards and requirements. The integration of Federal actions and state air quality planning is intended to “protect the integrity of the SIP by helping ensure that SIP growth projections are not exceeded, emissions reduction progress targets are achieved, and air quality attainment and maintenance efforts are not undermined” (58 FR 63214,

²⁴ Although EPA has had a PM_{2.5} NAAQS since 1997 (revised on October 17, 2006), PM_{2.5} SIP’s are not due for states with designated nonattainment areas for PM_{2.5} until April 2008 (EPA 2006h, 2006i).

²⁵ Concerns over alleged violations of the 2003 Ozone Season NO_x emission limitations specified in Mirant’s Stationary Source Permit have been resolved through a judicial consent decree between EPA, VDEQ, the State of Maryland, and Mirant (EPA 2004, 2006g).

63215; Nov. 30, 1993). In this case the Order not only conforms to the Virginia SIP by definition, but also achieves the overarching purpose of the general conformity principle.

The Order is exempt under the General Conformity regulations. Even if the Order does not conform to the Virginia SIP, the emissions generated from the Order fall within the “emergency” exceptions enumerated in the Virginia conformity regulations (9 VAC 5-160-30). A conformity determination is not required for “actions in response to emergencies or natural disasters such as hurricanes, earthquakes, etc., which are commenced on the order of hours or days after the emergency or disaster . . .” (40 CFR 93.153(d)2). “Emergency” is further defined in the Federal conformity regulations as:

A situation where extremely quick action on the part of the Federal agencies involved is needed and where the timing of such Federal activities makes it impractical to meet the requirements of this subpart, such as natural disasters like hurricanes or earthquakes, civil disturbances such as terrorist acts and military mobilizations. (40 CFR 93.152)

An emergency clearly existed on December 20, 2005. In fact, the very nature of DOE’s ability to issue the Order in the first place comes from the Department’s *emergency* authority under Section 202(c) of the Federal Power Act. It took DOE three months to understand the reliability situation at hand and determine the potential environment, health, and safety risks associated with the Plant’s shutdown. However, as soon as a line outage occurred (December 16, 2005) and the very real threat of a blackout in the Central D.C. area became apparent, DOE took quick action by issuing its Order. Therefore, DOE’s action qualifies as an emergency exception to the general conformity regulations.

4.3.1.7 Global climate change

A major worldwide environmental issue is the likelihood of major changes in the global climate (e.g., global warming) as a consequence of increasing atmospheric concentrations of “greenhouse” gases (IPCC 2001). The atmosphere allows a large percentage of incoming solar radiation to pass through to the earth’s surface and be converted to heat energy (infrared radiation) that does not pass back through the atmosphere as easily as the solar radiation passes in. The result is that heat energy is “trapped” near the earth’s surface.

Greenhouse gases include water vapor, CO₂, methane, nitrous oxide, O₃, and several chlorofluorocarbons. The greenhouse gases constitute a small percentage of the earth’s atmosphere; however, their collective effect is to keep the temperature of the earth’s surface about 60°F (33°C) warmer, on average, than it would be if no atmosphere existed. Water vapor, a natural component of the atmosphere, is the most abundant greenhouse gas. The second-most abundant greenhouse gas is CO₂, which has increased about 30% in concentration over the last century. Fossil fuel burning is the primary contributor to increasing concentrations of CO₂ (IPCC 2001). The increasing CO₂ concentrations likely have contributed to a corresponding increase in

globally averaged temperature in the lower atmosphere, which has increased by about 1–1.4°F (0.5–0.8°C) in the last hundred years (IPCC 2001).

Because CO₂ is relatively stable in the atmosphere and essentially uniformly mixed throughout the troposphere and stratosphere, the climatic impact of CO₂ emissions does not depend upon their source location on the earth. Instead, an increase in CO₂ emissions from a specific source is effective in contributing to global increases in CO₂ concentrations.

Carbon dioxide emissions from the Plant involve two components: CO₂ produced by the combustion of the carbon contained in the coal and CO₂ produced by chemical reactions as the trona removes SO₂ from the exhaust gases. These two components of Plant emissions are shown in Table 4.3.1-3 and are discussed in detail in the following paragraphs. Coal combustion is discussed first.

During four days in December 2005, when the Plant was running in pre-Order mode, the Plant burned 2,150 tons (1,950 metric tons) of coal. This coal produced 5,300 tons (4,800 metric tons) of CO₂. Operation of the Plant for a full year at the pre-Order level operations would be expected to produce about 480,000 tons (440,000 metric tons) of CO₂.

For the 285-day term of the Order (December 20, 2005, through September 30, 2006), the total amount of coal used by the Plant is estimated to be 566,000 tons (513,000 metric tons). This quantity of coal, when burned, would produce approximately 1.38 million tons (1.25 million metric tons) of CO₂. On an annualized basis operation of the Plant under the Order would be expected to produce at an annual rate of 1.76 million tons (1.60 million metric tons) of CO₂ per year.

During the one-year period immediately preceding the shutdown of the Plant in August 2005, the Plant generated power at an average rate of 210 MW, using an estimated 832,000 tons (755,000 metric tons) of coal. The combustion of this amount of coal produced approximately 2 million tons (1.8 million metric tons) of CO₂. These data can be used to represent the anticipated operation of the Plant during the two-month temporary extension until December 1, 2006, and through the duration of any additional extension of the Order (i.e., October 1, 2006, through December 31, 2007).

For all three cases above, the use of trona is assumed to result in 50% removal of SO₂ from the Plant's stack gases. To achieve this removal rate, trona needs to be fed at a 2.5 times higher than the rate theoretically calculated to be sufficient to react with all of the SO₂ in the stack gases. With the addition of heat CO₂ is released from trona in a calcining reaction. This results in approximately 0.009 lb of CO₂ being released from trona for each pound of coal burned. The resulting quantities of the CO₂ released from trona, as shown in Table 4.3.1-3, are a very small fraction of the CO₂ released by coal combustion.

To put the above numbers into perspective, global fossil combustion in the year 2003 resulted in emissions of approximately 28 billion tons (26 billion metric tons) of CO₂ (Marland et al. 2006).

Table 4.3.1-3. Annualized carbon dioxide emissions (tons/year) from the Mirant Plant during operational periods under analysis in this report

	Coal combustion	Trona utilization	Total from Plant
Pre-shutdown operations	2,000,000	0	2,000,000
Pre-Order operations	480,000	1,800	488,800
The Order (Dec. 20, 2005 – Sep. 30, 2006)	1,760,000	6,500	1,766,500
Potential extension of the Order (Oct. 1, 2006 – Dec. 19, 2007) ^a	2,000,000	7,500	2,007,500

Note: “Annualized” values were obtained by prorating the emissions during the actual period over a hypothetical 365-day period.

^aIncludes the period of the temporary extension of the Order until December 1, 2006.

4.3.2 Human Health

This section discusses the human health impacts of emissions from the Plant during two principal time periods: (1) the period of operations under the Order and (2) the duration of a potential extension of the Order. As a comparison, the health effects of the pre-Order mode of operation as well as the pre-shutdown operation of the Plant are also presented. The analysis in this section uses mathematical factors that relate a person’s exposure to concentrations of airborne pollutants to premature mortality and other health effects.

Potential human health effects resulting from the Order are a serious concern to DOE. A wide range of human health effects are associated with ambient concentrations of particulate matter and SO₂ as well as other NAAQS primary and secondary pollutants. Numerous epidemiological studies have demonstrated that increases in pollution levels are associated with increases in illness rates, use of health services, and earlier death among exposed persons.²⁶

Particle pollution, especially fine particle pollution (i.e., PM_{2.5}), contains microscopic solids or liquid droplets that are so small that they can get deep into the lungs and cause serious health problems. Numerous scientific studies have linked particle pollution exposure to a variety of problems, including:

- increased respiratory symptoms, such as irritation of the airways, coughing, or difficulty breathing,
- decreased lung function,
- aggravated asthma,
- development of chronic bronchitis,
- irregular heartbeat,

²⁶ Some recent information about air pollution health effects may be found in the Criteria Documents prepared to support EPA periodic reviews of the NAAQS; <http://www.epa.gov/ttn/naaqs/>.

- nonfatal heart attacks, and
- premature death in people with heart or lung disease.

People with heart or lung diseases, children, and older adults are most likely to be affected by particle pollution exposure. However, even healthy people may experience temporary symptoms from exposure to elevated levels of particle pollution.

Peak levels of SO₂ in the air can cause temporary breathing difficulty for people with asthma who are active outdoors. Longer-term exposures to high levels of SO₂ gas and particles cause respiratory illness and aggravate existing heart disease. SO₂ reacts with other chemicals in the air to form tiny sulfate particles. When these are breathed, they gather in the lungs and are associated with increased respiratory symptoms and disease, difficulty in breathing, and premature death.

4.3.2.1 Analytical approach

For the purposes of this SEA, DOE has used two techniques to estimate premature mortality due to Plant operations and has used one technique to estimate the incidence of other health effects. DOE analyzed all-cause mortality as a useful indicator of health effects because background mortality rates are readily obtainable and the association between air pollution and premature mortality²⁷ has well-documented response functions. DOE used a concentration-response function for premature mortality from Pope et al. (2002) to estimate the expected fatalities and to estimate the risk of premature mortality to a hypothetical maximally exposed individual in the community near the Plant. DOE used an EPA scaling technique (EPA 2005) to estimate premature mortality and other health effects to a much broader population.

For the assessment of health effects to persons in the local area, DOE used estimated PM_{2.5} and modeled SO₂ concentrations for a 36-mi² (93-km²) receptor grid comprised of 1,747 receptor locations with the Plant near its center (Figure 4.3.1-1). This area contains approximately 240,581 people.²⁸

In order to provide estimates of the adverse effects of various operating scenarios in this SEA, DOE has chosen all-cause mortality as the most useful single indicator of adverse health effects. Mortality is the most severe outcome in personal terms and also represents 90% or more of the associated cost in economic terms.

²⁷ The studies on which this environmental analysis is based analyzed all-cause mortality for cohort studies, which capture both short-term and long-term effects. *All-cause mortality* means fatalities that occur for any reason. Scientists studying the effects of air pollution use all-cause mortality rather than fatalities that are clearly tied to air pollution because accurately determining the cause of death is often impossible in epidemiological studies.

²⁸ The population estimates are based on individual, rectangular cells with a dimension of 15 seconds of one degree on each side. The populations within all such cells within the grid are interpolated to the U.S. Census Bureau's 2005 estimates (Personal communication between P. Coleman, Oak Ridge National Laboratory, and A.L. Sjoeren, Oak Ridge National Laboratory, June 5, 2006).

DOE used the adult (age 30 and older) PM_{2.5} concentration-response function (relative rate: 1.06 per 10 µg/m³, 95% confidence interval: 1.02–1.11) from Pope et al. (2002).²⁹ The Pope et al. (2002) study finds one of the strongest associations between PM_{2.5} exposure and premature mortality. Because SO₂ represents a significant proportion of the Plant's pollutant output, and SO₂ is known to convert to sulfate particles in ambient air, it is considered here as an addition to the estimated PM_{2.5} concentrations.³⁰ DOE assumed that SO₂ converts to sulfate particles as an addition to the PM_{2.5} loading at the rate of 7% per 24-hour period (Azad and Kitada 1998).

All cause premature mortality is calculated by multiplying the modeled pollutant concentration by the age specific population, the age specific all-cause death rate, and the concentration-response function to obtain the expected number of deaths. Sixty percent of the population in Virginia is aged 30 or older (Virginia Department of Health 2004). For the receptor grid DOE studied this yields an estimate of 144,000 persons 30 or older. For this age group, the annual, all-cause death rate is 13 per 1,000 (Virginia Department of Health 2004).

To estimate several other health effects from particulate matter resulting from plant operations, DOE used a scaling technique developed by EPA based on extensive air quality modeling (EPA 2005). The method involves interpolation among cases that were modeled in detail by EPA. DOE used parameters provided by EPA to estimate health effects incidence based on total emissions of SO₂, NO_x, and PM_{2.5} from the Plant (Personal communication between B. Hubbell, EPA, and L.N. McCold, Oak Ridge National Laboratory, October 11, 2006). The potentially affected population on which these estimates are based is roughly the population of the eastern United States. While the risks to persons who live near the Plant are largest, the expected incidence includes the sum of very small risks to millions of people.

4.3.2.2 Results

DOE estimated the expected incidence of premature mortality among the 144,000 adult population (age 30 or older) in a 36-mi² (93-km²) area centered on the Plant (Figure 4.3.1-1). The results of the analysis of health effects to the adult population are described by the following bullets:

- As a result of exposure to the combined effects of SO₂ and PM₁₀, the expected incidence of premature mortality among the 144,000 adults (30 and older) in a 36-mi² (93-km²) area around the Plant from *pre-shutdown operations* is about 3.8 (confidence interval: 1.2 to 6.8) per year.

²⁹ EPA employs the Pope et al. PM_{2.5}-related mortality estimates as one component in cost/benefit analyses of various air pollution reduction strategies (EPA 2005). Information on EPA's studies and the methodology can be found in the Regulatory Impact Analysis for the Final Clean Air Interstate Rule (EPA-452/R-05-002, March 2005), which may be found at <http://www.epa.gov/air/interstateairquality/pdfs/finaltech08.pdf>.

³⁰ NO_x is also known to convert to PM_{2.5} in the atmosphere. DOE did not include NO_x in the analysis of nearby health effects because NO_x is a relatively smaller part of Plant pollution emissions and converts to PM_{2.5} less efficiently than SO₂.

- For *pre-Order operations*, the expected incidence of premature mortality among the exposed population of 144,000 adults (30 and older) would be 0.77 (confidence interval: 0.26 to 1.4) per year.
- For *operations under the Order* the expected incidence of premature mortality among the adult population of 144,000 is 1.3 (confidence interval: 0.44 to 2.4). The annual rate for operations under the Order is 1.7 (confidence interval: 0.58 to 3.1).
- For *potential extension of the Order* through June 2007 the expected incidence of premature mortality among the adult population of 144,000 would be 1.5 (confidence interval: 0.51 to 2.7) Extending it through December 2007 would raise the expected fatalities to 2.9 (confidence interval: 0.97 to 5.1). The annual rate for extension of the Order is 2.3 (confidence interval 0.78 to 4.1).

The reader should understand that the estimates of expected fatalities above do not indicate the risk faced by any particular individual. Pollutants do not affect all sectors of the population to the same extent. The very young, the elderly, and those with preexisting health conditions tend to experience adverse health effects at pollutant levels that have little or no effect on the remainder of the population. Activity levels also affect the nature of the health effects; the more active the person, the more likely that PM or SO₂ will induce health effects. For instance,

jogging while pollution levels are high is more likely to cause health effects in healthy people than would resting on a picnic bench or walking slowly. The reader should also bear in mind that among the modeled population of 144,000 adults, about 1,800 would die each year due to various causes.

Statistical Terminology

The results of the health effects analysis are expressed in statistical terms.

Some results are expressed as the **expected incidence** of a specified health effect occurring in the exposed population. For instance, if pepper were thrown into the faces of 1,000 people in 100 groups of 10 people and 340 of the people sneezed, for the next randomly selected group of 10 people, the expected incidence of sneezing would be 3.4 people. In each group of 10, the number of people sneezing would be a whole number. Sometimes it would be three people, sometimes it would be four, and it could as small as zero or as high as 10, but for this hypothetical example the long-term average would be 3.4. Expected incidence, in this case 3.4, is not a statement about what will occur, but a statement of what is likely to occur.

Other results are expressed as the **probability** that an individual who is exposed would experience the specified health effect. For the example above, the probability that any one random individual would sneeze would be 0.34 (=340/1000).

Another example shows how probability statements can be interpreted for groups and individuals. In 2003 approximately 25 per 100,000 (0.00025 or 0.025%) Americans 50 years of age or older, were diagnosed with stomach cancer. This can be reported as an expected incidence of 25 stomach cancers per 100,000 Americans age 50 or older. For an average American 50 or older, the probability per year of being diagnosed with stomach cancer is 0.00025.

Another useful indicator of the potential health effects of the Order is the risk to the “maximally exposed individual.” The maximally exposed individual is a hypothetical person who spends all his time outdoors at the receptor point that has the highest average modeled concentration. Nobody stays at the same place all the time, so the maximally exposed individual establishes the upper limit on the health risk that anyone could experience. However, the response factor used to generate these estimates is for the average adult (30 or older). Persons who are more susceptible to air pollutants would have a higher risk and healthy people would have a smaller risk.

- For *pre-shutdown operations* the hypothetical maximally exposed individual has a risk of premature mortality of 0.22% (confidence interval: 0.074 to 0.39%) for a year of operation.
- For *pre-Order operations* if they had continued for one year, the risk of premature fatality to the hypothetical maximally exposed individual would be 0.028% (confidence interval: 0.0094 to 0.050%)
- For *operations under the Order* the risk of premature mortality from SO₂ concentrations to the maximally exposed individual is 0.072% (confidence interval: 0.024 to 0.13%).
- For a *potential extension of the Order* through June 2007, the risk of premature mortality to a hypothetical maximally exposed individual would be 0.067% (confidence interval: 0.022% to 0.12%). If the Order were extended through December 2007, the hypothetical maximally exposed individual risk of premature mortality would be 0.13% (confidence interval: 0.045 to 0.24%).

Confidence Intervals

A confidence interval is one expression of the uncertainty associated with a statistical estimate. To be clearly defined, the confidence interval needs to specify the confidence level associated with the interval. The confidence intervals reported in this SEA are for a 95% confidence level. For example, if the estimate of the probability of a health effect is 0.30, it means that the best estimate of the probability is 0.30. If the associated 95% confidence interval is 0.17 to 0.48, it means that while the estimate is not certain, we are 95% confident that the true probability of the health effect is no lower than 0.17 and no higher than 0.48.

A confidence interval is helpful in informing us of how much confidence we can have in a statistical estimate. For example, if the confidence interval above were 0.29 to 0.31, we would know that we could be very confident in the estimate of 0.30. Conversely, if the confidence interval were 0.01 to 0.99, we would know to have much less confidence that 0.30 was close to the true value.

There are important uncertainties that are relevant to both the maximally exposed individual and population analyses. First, there are uncertainties associated with the response factors as indicated by the 95% confidence intervals. (See text box.)

Another uncertainty is the health status of the affected persons. If the persons exposed to the highest concentrations are more healthy than average, the risks are lower. Conversely, if the people exposed to the highest concentrations are relatively unhealthy, the estimated premature fatality probability may be an underestimate. Further, there is uncertainty associated with the location of affected persons, e.g., people who may not be at home all day or workers who may be

outside much of the day, so their actual exposures may be lower or higher than assumed for this analysis. To reduce these uncertainties would require very detailed information about the health status and daily movements of a large number of people. Such detailed information is not available.

Another important uncertainty has to do with the air dispersion modeling. As discussed in Section 4.3.1, many assumptions and approximations were used in the air dispersion analysis. Where there was uncertainty, DOE selected assumptions that avoid underestimating the impacts of Plant operations. The net result of all these assumptions is most likely to overestimate maximum pollutant concentrations. In addition, Mirant has stated that the standard building dimensions used in AERMOD lead to overestimating the modeled downwash effect, with the result that modeled concentrations at Marina Towers are unrealistically high. EPA authorized Mirant to initiate the MES to help resolve this concern. Initial monitoring results for SO₂ monitors near the Plant tend to support Mirant's statement, but EPA has yet to reach a conclusion.

If the estimate of the downwash effect is too high, it would mean that the maximum exposures to stack emissions are overestimated and the risk to the hypothetical maximally exposed individual may be too high. However, overestimate of the risk to the hypothetical maximally exposed individual may not appreciably affect the risk to the population. The population health effect is the sum of the individual risks for the modeled population of 144,000 adults. Relatively few people live in the top floors of Marina Towers. Even if modeling with improved input parameters showed that pollutant concentrations at Marina Towers are lower than current estimates, the concentrations at points that are farther away and the exposures for most of the population would be little affected. Thus, the population risk is not expected to be much affected by more accurate modeled building dimensions.

EPA Scaling Technique. The EPA scaling technique is a simple method of making estimates of a variety of health effects. The health effects reported in Table 4.3.2-1 are those examined by EPA in its recent regulatory impact assessments for emission standards. The estimates of population health effects are higher than those that would result from the method above because the potentially affected population is much larger. The EPA scaling technique does not provide estimates of uncertainty or confidence intervals. However, the estimates of premature mortalities are based on Pope et al. (2002) cited above. Consequently, at least for the premature mortalities, it is reasonable to estimate that a 95% confidence interval would span at least 70% below to 80% above the expected incidences reported in Table 4.3.2-1 based on Pope's reported confidence intervals.

4.3.3 Water Quality

Two types of water quality impacts could result from Plant operations as a result of the Order. Plant operations could cause direct impacts to Potomac River water quality by changing the volume or characteristics of the effluent discharged from the Plant. Indirect impacts to regional water quality could result from changes in the emissions of air pollutants that are

Table 4.3.2-1. Expected incidence of short- and long-term health effects resulting from Mirant Plant operations for the population of the eastern United States

Health effect	Pre-shutdown (one year)	Pre-Order (285 days)	Order (285 days)	Order extension Oct. '06 – Jun. '07	Order extension Oct. '06 – Dec. '07
Premature mortality (adults, 30 and over)	37	5	14	12	23
Infant mortality (infants less than one year)	0.08	0.01	0.03	0.03	0.05
Chronic bronchitis (adults, 26 and over)	20	3	7	6	13
Non-fatal myocardial infarctions (adults, 18 and older)	50	7	18	16	31
Hospital admissions – Respiratory (adults, 20 and older)	13	2	5	4	8
Hospital admissions – Cardiovascular (adults, 20 and older)	11	2	4	3	7
Emergency room visits for asthma (18 and younger)	30	4	11	9	19
Acute bronchitis (children, 8-12)	46	7	17	14	29
Asthma exacerbations (asthmatic children, 6-18)	698	101	258	218	440
Lower respiratory symptoms (children, 7-14)	553	80	205	173	349
Upper respiratory symptoms (asthmatic children, 9-11)	423	61	157	132	267
Work loss days (adults, 18-65)	3,942	568	1,459	1,234	2,488
Minor restricted activity days (adults, age 18-65)	23,490	3,387	8,693	7,350	14,823

Source: DOE analysis of SO₂, NO_x, and PM_{2.5} emissions from the Mirant Potomac River Generating Station, using EPA scaling technique (Personal communication between B. Hubbell, Health and Environmental Impacts Division, EPA, Research Triangle Park, North Carolina, and L.N. McCold, Oak Ridge National Laboratory, October 11, 2006).

subsequently deposited in surface waters or that are washed into surface waters after being deposited on the ground surface.

4.3.3.1 Direct impacts to the Potomac River

The operating changes associated with the pre-Order period or operations under the Order do not change the water quality characteristics of Plant intake water and effluents. Thus, the effect of the Plant on the pollutant load in the Potomac River (including suspended sediments, coliform bacteria, and metals) under different operating conditions can be assumed to be proportional to the volume of water used and discharged by the Plant. No chlorine was used in the Plant during pre-Order operations or under the Order; thus, Plant operations do not affect chlorine levels in the Potomac River.

Pre-shutdown operations. Under pre-shutdown operating conditions the Plant used Potomac River water and discharged effluents to the river as described in Section 2. The effects of many years of Plant operations are among the natural and human factors reflected in the existing water quality and ecological conditions in the river, as described in Sections 3.3.2.1 and

3.4.2.1. Table 2.4-1 presents data on the water quality of intake water and effluents associated with pre-shutdown operations.

Pre-Order operations. The Plant's water discharges to the Potomac River in December 2005 (assumed to be typical of pre-Order conditions) averaged 94 million gal/day (360,000 m³/day), approximately 27% (on average) of the average pre-shutdown discharge volume (Section 2.4.2). Assuming that withdrawals from the river during any period are about 1% higher than monitored discharges (Section 2.3), withdrawals during this pre-Order period are estimated at less than 95 million gal/day (360,000 m³/day). The reported maximum thermal discharge to the river in December 2005 was 969 Mbtu/hr. The much lower water and thermal discharge rates associated with pre-Order operations could contribute to improved river water quality relative to pre-shutdown operations, which could improve conditions for aquatic organisms (Section 4.3.4.2).

Operations under the Order and potential extensions of the Order. The Plant's water and thermal discharges to the river varied during the 285-day period of the Order. Operations during the line outage in January 2006 contributed to an average water discharge for the entire month of 266 million gal/day (1.0 million m³/day), nearly three times the discharge recorded in the pre-Order period. Reported maximum thermal discharge to the river was 3,355 MBtu/hr, more than three times the December maximum. Operations in the period February through May 2006, a period of relatively low power demand (Figure 4.2-1) during which there were no line outages, resulted in an average discharge of 170 million gal/day (640,000 m³/day), about 80% higher than pre-Order operations but only about half of the average for the pre-shutdown period. Maximum thermal discharges in this period ranged from 1,157 to 1,620 MBtu/hr. Average water discharge in June 2006 was 250 million gal/day (950,000 m³/day). This value is 165% higher than discharge under pre-Order conditions, but is still 27% less than the average discharge under pre-shutdown operations before August 2005. Maximum thermal discharge in June 2006 was 2,406 MBtu/hr, which also is intermediate between pre-shutdown and pre-Order levels. The somewhat lower water and thermal discharge rates resulting from operations under the Order through June 2006 could contribute to improved river water quality relative to pre-shutdown operations, which could improve conditions for aquatic organisms (Section 4.3.4.2).

For operations under the Order following the commencement of daily predictive modeling in July 2006 (including the temporary extension of the Order to December 1, 2006, and any extension beyond that date), water and thermal discharges are assumed to be similar to those during pre-shutdown operations. Impacts are estimated to be the same as for pre-shutdown operations.

4.3.3.2 Indirect impacts to regional water quality

DOE identified and assessed two potential sources of indirect impact to regional water quality from deposition of Plant air pollutants: (1) nitrogen loading and (2) acid deposition.

Nitrogen loading. Deposition of nitrogen compounds emitted from the Plant contributes to nitrogen input to Chesapeake Bay and other waters in the region, thus contributing to the nutrient loading that degrades water quality (Section 3.3.2) and can impact aquatic organisms (Section 4.3.4).

Targets for reducing atmospheric nitrogen inputs have been set for the Chesapeake Bay as a whole (Section 3.3.2.5), but not for component watersheds. Therefore, DOE's assessment of the potential impacts of Plant operations on nitrogen loading to area surface waters focuses on Chesapeake Bay. Because nitrogen inputs due to pre-shutdown operations of the Plant are implicitly included in current Bay nutrient budgets, the reduced levels of operations associated with pre-Order conditions and the Order contribute toward the Chesapeake Bay Program's 8-million-lb (3.6-million-kg) target for reduction in atmospheric inputs of nitrogen (Section 3.3.2.5). In all cases the estimated reductions in nitrogen loading are small when compared with the total nitrogen input to the Bay.

Assumptions. DOE estimates (Section 4.3.1.5) that the Plant emitted 2,800 tons (2,500 metric tons) of NO_x per year under pre-shutdown operating conditions. In estimating the impacts of nitrogen emissions from the Plant on Chesapeake Bay water quality, DOE assumes that NO_x has the same nitrogen content as an equivalent mass of NO₂; the pre-shutdown NO_x emission is the equivalent of about 1.7 million lb/yr (770,000 kg/yr) of nitrogen.

To estimate the impact of the Plant on Chesapeake Bay nitrogen loading, DOE assumed that 10% of the nitrogen released from the Plant reaches the Bay, primarily due to being deposited directly on water or on impervious urban surfaces, while all other nitrogen emitted from the Plant is either consumed in terrestrial or aquatic ecosystems or deposited outside the Bay watershed (e.g., on the open Atlantic Ocean). (See Section 3.3.2.5.)

The above assumption is believed to be realistic, based on the following reasoning. Assuming that electric power plants such as the Plant are responsible for 38% of the atmospheric contribution of nitrogen to the Bay (consistent with their contribution to regional NO_x emissions, as discussed in Section 3.3.2.5), the total estimated electric-utility contribution to the Bay is about 35 million lb/yr (16 million kg/yr). The 170,000 lb/yr (77,000 kg/yr) of nitrogen estimated to reach the Bay as a result of Plant air emissions (10% of the total nitrogen emissions) are approximately 0.5% of this total electric-utility contribution. This 0.5% value is consistent with power-plant NO_x emissions inventories reported by EPA (2006b), which indicate that during several months in early 2005 the Plant accounted for about 0.5% of electric utility NO_x emissions in the seven-state region (i.e., Maryland, Virginia, Pennsylvania, New York, West Virginia, New Jersey, and Ohio) estimated to produce most of the air emissions that contribute nitrogen to the Bay.

Pre-shutdown operations. Based on the above assumptions and the Plant's estimated NO_x emissions under pre-shutdown operating conditions, pre-shutdown Plant operations contributed about 170,000 lb (77,000 kg) of nitrogen to the Bay annually, or about 0.2% of the total annual nitrogen input to the Bay that is attributed to atmospheric sources (Section 3.3.2.5).

Pre-Order operations. Based on the estimate of NO_x emissions presented in Section 4.3.1.5, pre-Order operations are estimated to emit nitrogen at an annual rate of about 470,000

lb/yr (220,000 kg/yr). For the 285-day duration of the Order (through October 1, 2006) operations at pre-Order levels would emit about 370,000 lb (170,000 kg) of nitrogen.

Assuming that 10% of the nitrogen from the Plant reaches the Bay, pre-Order operations, if extended for a full year, would contribute about 47,000 lb (22,000 kg) of nitrogen to the Bay annually. Compared with pre-shutdown operations, pre-Order operations would avoid an estimated 123,000 lb (55,000 kg) of annual nitrogen delivery to the Bay, thus potentially achieving about 1.5% of the Chesapeake Bay Program's targeted 8-million-lb (3.6-million-kg) reduction in atmospheric nitrogen input.

Operations under the Order. Based on the estimate of NO_x emissions presented in Section 4.3.1.5, operations under the Order emit nitrogen at a rate of about 1.5 million lb/yr (670,000 kg/yr). For the 285-day duration of the Order (through October 1, 2006) operations under the Order emit 1.2 million lb (530,000 kg) of nitrogen, delivering nitrogen to the Bay at an estimated rate of 150,000 lb (67,000 kg) per year. If sustained for a full year this level of operations would avoid about 20,000 lb (10,000 kg) of pre-shutdown nitrogen delivery to the Bay annually and would achieve about 0.2% of the Chesapeake Bay Program's goal for annual atmospheric nitrogen reductions.

Potential extension of the Order. DOE's analysis assumes that Plant operations after October 1, 2006, including operations during the temporary extension of the Order through December 1, 2006, and any subsequent extension of the Order, would utilize coal and emit NO_x at approximately the same rate as pre-shutdown operations, so there would be no reduction from pre-shutdown nitrogen delivery to the Bay and no contribution toward meeting the Chesapeake Bay Program's nitrogen-reduction goals.

Acid deposition. The Plant's air emissions of SO₂ and NO_x (Section 4.3.1) contribute to regional acid deposition. However, under all operating conditions acid-deposition impacts to water quality of streams in nearby watersheds, including the Anacostia, Patuxent, and nearby portions of the Potomac watershed, would be negligible because these watersheds are well buffered against acid rain (Section 3.3.2.6).

Pre-Order operations. Air emissions of SO₂ and NO_x under pre-Order conditions were about 28% of pre-shutdown emissions of these pollutants, proportionately reducing the Plant's contribution to regional acid deposition, relative to pre-shutdown operations.

Operations under the Order. Compared to pre-Order operations, operations under the Order increase the Plant's contribution to regional emissions of these air pollutants that produce acid deposition, but the Plant's contribution is smaller than under pre-shutdown operations. Over the 285-day duration of the Order, the Plant produced about 87% of the NO_x emissions that would have occurred for the same duration of pre-shutdown operations, but roughly three times the emissions estimated for pre-Order operations. SO₂ emissions also increased relative to pre-Order operations, but the use of trona caused emission of less than 45% of the SO₂ that would have been emitted from pre-shutdown operations.

Potential extension of the Order. Operations under the Order after October 1, 2006, including during the temporary extension of the Order to December 1, 2006, and any extension

beyond that date, are conservatively estimated to emit NO_x at the same annual rate as pre-shutdown operations, but use of trona is assumed to reduce SO₂ emissions by 50% compared with pre-shutdown operations. Thus, the Plant's overall contribution to regional acid deposition is smaller than under pre-shutdown operations.

4.3.4 Ecological Resources

Operation of coal-fired power plants can impact ecological resources through air, water, or solid waste releases that can result in acid deposition, nutrient enrichment (see section 4.3.3.2), or changes in water quality or quantity of the receiving bodies (Dvorak et al. 1978, EPA 2006c).

4.3.4.1 Acid deposition

Acid deposition can affect plant and animal species, both directly and indirectly (Schreiber 1995, Roth et al. 2005, EPA 2006a), but Plant emissions (discussed in Sections 3.3.2.6 and 4.3.3.2) are expected to have minimal impacts as described below.

Aquatic impacts. The ecological effects of acid rain are most clearly seen in aquatic environments (e.g., streams, lakes, marshes) located in watersheds where the soils have a limited buffering capacity (EPA 2006a). (See Section 3.3.2.6.) In areas where buffering capacity is low, acid rain can release aluminum, which is highly toxic to many species of aquatic organisms, from soil into lakes and streams. In general, lowering the pH of a water body can impair the ability of certain fish and other aquatic organisms to grow, reproduce, and survive.

Soils in the river and stream basins in the region where air emissions from the Plant are most likely to fall (e.g., Potomac, Anacostia, and Patuxent rivers; Rock Creek) are generally well buffered (CBWP-MANTA 2001, Roth et al. 2005, Shanks 2005; also see Sections 3.3.2.6 and 4.3.3.2). Mobilization of aluminum is, thus, unlikely to occur, and acid deposition will not greatly change the pH level of the streams. Therefore, acid deposition resulting from the DOE Order, including the temporary extension of the Order to December 1, 2006, and any extension beyond that date, would have minimal impacts on biological resources in regional waterways.

Terrestrial impacts. Increases in soil acidity can impair the ability of some species of trees to grow and resist disease, while dry deposition of acidic gases and particles can directly impact some terrestrial vegetation.

The effects of over 50 years of Plant operations are among the natural and human factors reflected in the existing ecological conditions near the Plant, as described in Section 3.4.1. Vegetation still actively grows nearby on Daingerfield Island and in the small wooded area next to the Plant (Figure 2-2). While the Order results in higher emissions of the air pollutants responsible for acid deposition than occurred during the pre-Order period (Sections 4.3.1 and 4.3.3.2), combined total estimates of emissions of these pollutants under the Order and any

extension of the Order, including the temporary extension, are still lower than during pre-shutdown operations, when vegetation was growing well near the Plant. Thus, the Order is unlikely to have negative impacts from acid deposition on vegetation or the wildlife that depends on it.

4.3.4.2 Impact of water quality changes

Nutrients. One of the main causes of aquatic habitat loss in the Chesapeake Bay watershed as a whole (CBP undated) is elevated loading of two nutrients: nitrogen and phosphorus. (See Section 3.3.) To the extent that the DOE Order changes loading of these two nutrients to surface waters compared to the pre-Order or pre-shutdown operating periods, there could be effects on habitats in the river for fish and submerged aquatic vegetation (Section 3.4.2.6), but the Plant's impact on nutrient loading would be small relative to the total.

As discussed in Section 4.3.3.2, nitrogen compounds are emitted from the Plant and augment the nitrogen input to Chesapeake Bay and other waters in the region, thus, contributing to the nutrient loading that impacts aquatic organisms and their habitat. During the first six months of operations under the DOE Order, the Plant's contribution to the nitrogen in the Bay increased over the pre-Order value, but was still lower than under pre-shutdown operating conditions. Operations under daily predictive modeling are estimated to contribute a similar amount of nitrogen as pre-shutdown operations. In all cases changes in the Plant's contribution of atmospheric nitrogen to the Bay are small (as discussed in Section 4.3.3.2), when compared with the total nitrogen input to the Bay.

Reported phosphorus levels in Plant water effluent (Table 2.4-1) were lower than those in the intake water, suggesting that Plant water use may reduce the phosphorus load and, thus, benefit aquatic systems. If the Plant reduces phosphorus concentration in effluent by 0.016 mg/L (Table 2.4-1), effluent discharge at the pre-shutdown rate of almost 345 million gal/day (1.3 million m³/day) would remove about 48 kg/day of phosphorus. Reduced operating levels during pre-Order operations and the first six months of the DOE Order would have diminished the Plant's beneficial impact by removing proportionately less phosphorus than pre-shutdown operations or operations under daily predictive modeling. At any level of operations, however, any beneficial impact on phosphorus load resulting from Plant operations is small relative to the total daily input (from all sources) of phosphorus to the Potomac River, which has been estimated to be about 8,000 kg/day (Boynton and Swaney 1998), or the contribution of the nearby Blue Plains Wastewater Treatment Plant, which delivers 720 kg/day of phosphorus to the river when operating at its rated capacity of 370 million gal/day (1.4 million m³/day) and discharging effluent with the phosphorus concentration of 0.18 mg/L allowed by its NPDES permit (Table 3.3-1).

Other contaminants. As discussed in Section 4.3.3.1, changes under the Order in the amount of water used and discharged by the Plant could cause proportional, but small, changes

in concentrations of other pollutants removed from or returned to the Potomac River that are unlikely to result in impacts to organisms or their habitats in the Potomac River.

Trona use. Use of trona may change the landfill effluent discharged to Mataponi Creek by increasing pH and concentrations of sodium sulfate, sodium chloride, selenium, arsenic, and dissolved metals. (See Section 4.3.5.) Modest increases in pH that result from carbonate leaching could be beneficial to aquatic life in the creek due to buffering of acidity. Sulfate compounds are neither toxins nor nutrients; thus, increased concentrations of sodium sulfate would not be expected to impact the creek's aquatic life. Any increase in sodium chloride would likely be indistinguishable from background.

Release of arsenic and selenium could, however, have adverse impacts on aquatic biota and other wildlife that consume these organisms, depending upon the levels at which they occur in the effluent. As noted in Section 4.3.5, monitoring of collected landfill leachate and stormwater, as required under the existing discharge permit, should identify the potential for any problems from selenium before discharges occur. Arsenic levels are not, however, currently monitored prior to water discharge, so there is a potential for arsenic to be released to the creek at concentrations that could be harmful to aquatic life.

Selenium can enter the food web from both sediments and surface water (EPA 2006e). In the food web it undergoes bioconcentration, bioaccumulation, and biomagnification as organisms that first take it in are eaten by others. Elevated levels cause growth reduction in green algae. In other aquatic organisms a number of adverse effects have been observed including loss of equilibrium and other neurological disorders, liver damage, reproductive failure, reduced growth, reduced movement rate, chromosomal aberrations, reduced hemoglobin and increased white blood cell count, and necrosis of the ovaries.

Arsenic can cause cancer and genetic mutations in aquatic organisms, with those effects including behavioral impairments, growth reduction, appetite loss, and metabolic failure (EPA 2006e). Aquatic bottom feeders are more susceptible to arsenic than other organisms.

4.3.4.3 Impacts of changes in water use

Once-through cooling water systems such as used by the Plant can impact aquatic species by impingement (when aquatic organisms become trapped on the intake screens), entrainment (when aquatic organisms are taken in and pass through the cooling water intake system), or thermal changes (Jensen 1981). Impingement and entrainment are often roughly proportional to the volume of water withdrawn, as well as the numbers and species of aquatic organisms in the water body. At the Plant the numbers and species of fish, crabs, and other aquatic organisms that are susceptible to impingement or entrainment at any one time depends on the season of the year, annual fluctuations in relative abundance, and the impact of restoration activities in the Chesapeake Bay watershed. Overall, the effect on species or their habitats of water use and changes in water use by the Plant in different operation modes is expected to be small. The

Plant's thermal discharge is permitted and has been shown to not form a barrier to movement or cause lethality of aquatic organisms.

Impingement. Mirant studied impingement at the Plant during 1981-1982 and 2003-2004 (Pepco 1982; Personal communications between A. Wearmouth, Mirant Corporation, and M.S. Salk, Oak Ridge National Laboratory, July 24, and August 18, 2006). Rates of cooling water withdrawal at the Plant were similar for both study periods (i.e., pre-shutdown conditions). For 1981-1982 the estimated impingement was 206,379 finfish³¹ and 56,600 blue crabs; for 2003-2004 the annual estimates were 19,392 finfish and no blue crabs. In the 1981-1982 study over 90% of the fish were impinged in the winter and spring. The main fish species impinged in both studies were species that were either not used commercially (e.g., gizzard shad) or were too small to be of commercial value (e.g., white perch). Some fish exhibited disease conditions or appeared stunted, indicating that they were in poor health.

Although the 2003-2004 study is likely more representative of the fish community that is currently susceptible to impingement by the Plant, the large differences in the results of the two studies illustrate the potential magnitude of annual variation in potential impacts, so results of both studies were used as a basis for assessing impacts of the Order.

Impingement is assumed to be proportional to water intake for the Plant. At pre-Order operating levels the Plant withdraws about 27% of the amount of water it used during the pre-shutdown period. (See Section 4.3.3.1.) Thus, impingement under pre-Order conditions is estimated to amount to about 5,200–55,000 fish per year, based on the levels observed during the two studies at the Plant.

Under the Order before the commencement of daily predictive modeling (i.e., between January and June 2006), monthly Plant water use ranged from 42 to 77% of monthly use in the pre-shutdown period, averaging about twice the use during the pre-Order period. Assuming that 90% of annual impingement occurs during the winter and spring months of January through June, impingement during this time period is estimated at approximately 9,400–99,000 fish. At the high end of the range the number of fish impinged under the Order on an annual basis is equivalent to about 3% of the estimated 4.9 million fish in the Potomac-Washington Metro Basin (Maryland DNR undated-b).

Following the commencement of daily predictive modeling in July 2006, the Plant is assumed to withdraw water at pre-shutdown levels, resulting in annual impingement rates within the range indicated by the two studies (i.e., about 19,000–206,000 fish per year). However, because the 1981-1982 study indicated that less than 10% of annual impingement occurs during the summer months, operations under the Order during the period July through September 2006 are estimated to have impinged fewer than 1,900–21,000 fish. The temporary extension of the Order to December 1, 2006, and any extension beyond that date would result in cooling water

³¹ The number of fish impinged is for the 56-week duration of the study. Thus, the annual rates would be slightly less.

withdrawal rates and annual impingement rates similar to pre-shutdown conditions (i.e., about 19,000–206,000 fish per year).

Not all impinged fish are killed; new intake screens, particularly the one with the fish buckets (Section 2.2), should lower impingement mortality. Fish or other organisms impinged on the water intake screens are washed off the screens and returned to the river on the south side of the cove area next to the Plant, south of the water intake area. (See Figure 2.1-1.)

Little impact is expected to the blue crab population as studies have indicated that initial and latent mortality from impingement is less than 10% (Pepco 1982). Also, blue crabs are found near the Plant only in years when the river is particularly salty (Personal communication between A. Wearmouth, Mirant Corporation, and M.S. Salk, Oak Ridge National Laboratory, August 17, 2006). A difference in the salt level in the river between the two impingement studies is the likely explanation for the difference in the observed number of impinged crabs.

Entrainment. Mirant studied entrainment of fish eggs and larvae at the Plant in 1981 and 2005. Preliminary results from the 2005 study are similar to those from the 1981 study reported below (Pepco 1983; Personal communication between A. Wearmouth, Mirant Corporation, and M.S. Salk, Oak Ridge National Laboratory, August 25, 2006).

Only organisms small enough to pass through the screens on the water intakes are drawn into the Plant where they are subjected to heat, fluid, and mechanical stresses (Cada et al. 1981). Entrainment of fish eggs and larvae is mainly an issue in the period during and soon after fish spawning, from early spring through mid-summer.

During the 1981 study, eggs and larvae of anadromous species (i.e., white perch and herring) were 99% of the total number entrained. Freshwater species (e.g., minnows [fish in the Cyprinidae family], tessellated darter [*Etheostoma olmstedii*]) were entrained in very low numbers, less than 1% of the total.

The major spawning area for both white perch and herring is about 9 miles (14 km) above the Plant at Little Falls. As they mature, the larvae float downriver, past the Plant, mostly in a dredged channel well offshore. The Plant draws cooling water primarily from shallow water near shore, which results in relatively low entrainment rates. Significant spawning of white perch and herrings also occurs in other portions of the Potomac River and its tributaries. Thus, while some fish spawn in the Washington, D.C. portion of the Potomac River, spawning there represents a small portion of the spawning of the Potomac River population. The best estimate of the percent entrainment varied from 1.6% for white perch yolk-sac larvae (an early larval stage) to 8.7% for herring larvae after yolk absorption (Pepco 1983).

Pre-Order operations. There would have been no entrainment of fish eggs and larvae during pre-Order conditions in December 2005 because of the absence of these organisms from the Potomac River at that time. On an annual basis, assuming that entrainment is proportional to water intake, pre-Order conditions would result in entrainment at about 27% of pre-shutdown rates.

Operations under the Order. Under the Order before the commencement of daily predictive modeling (i.e., during January through June 2006) entrainment is estimated to have

occurred at approximately twice the calculated pre-Order rates, but substantially less than pre-shutdown levels (about 55% of pre-shutdown rates). Following commencement of daily predictive modeling in July 2006, entrainment is estimated to have been similar to pre-shutdown conditions for the summer season (owing to similar cooling water withdrawal rates). The temporary extension of the Order to December 1, 2006, and any extension beyond that date would be expected to result in entrainment rates similar to those that occurred during the pre-shutdown time period.

Since entrainment was not a major issue when the Plant was operating at the pre-shutdown level before August 2005, entrainment resulting from operations under the Order or any extension of the Order would not have a major impact on fish populations.

Temperature changes. The Plant's NPDES permit (Section 2.4.2) limits temperature rise in the Potomac River from water discharge to 2.8°C above ambient temperature beyond a 1,000-ft (300-m) radius in order to prevent formation of a barrier to movement of aquatic life or lethality to passing organisms. Based on a 2001 study (Mirant 2002), the thermal plume from the Plant does not form a barrier to movements of aquatic life or cause lethality to passing organisms. The main path for movement of aquatic organisms is the river channel, which is unaffected by the warm water plume from the Plant (Mirant 2002). Thus, no blockage to aquatic life movement is expected from the thermal plume under any assessed operating conditions.

If pre-Order operating conditions continued throughout the year, slightly lower summer water temperatures would result. This could slightly reduce the potential for nuisance algal blooms (Section 3.4.2). Similar, but smaller, benefits could be expected in 2006 because Plant operations under the Order before the commencement of daily predictive modeling resulted in thermal input levels intermediate between pre-Order and pre-shutdown operations (Section 4.3.3.1). Following commencement of daily predictive modeling in July 2006 and throughout any extensions of the Order, however, thermal input to the river is assumed to be similar to pre-shutdown conditions.

If there were a sudden shutdown of the Plant during the winter under any operating conditions, fish that were acclimated to the warm discharge might suffer cold shock when they lose the warm water habitat.

4.3.4.4 Special status species

The NPDES permit stated that the Fish and Wildlife Service (FWS) and the National Marine Fisheries Service (NMFS), the agencies responsible for implementing the Federal Endangered Species Act (ESA), had indicated that the Plant's wastewater discharges were not adversely affecting the three Federally listed species mentioned in the permit. (See Section 3.4.2.)

During consultation with Mirant before the start of sampling for an entrainment study, FWS concluded that taking of eggs of the shortnose sturgeon, an endangered species, in the sampling process was not an issue as there was no possibility of finding them (Personal

communication between A. Wearmouth, Mirant Corporation, and E.D. Smith, Oak Ridge National Laboratory, July 14, 2006).

While bald eagles are occasionally seen near the Plant, the site provides no suitable nesting habitat for them (Personal communications between A. Wearmouth and D. Knight, Mirant Corporation, and M.S. Salk, Oak Ridge National Laboratory, July 24, and 25, 2006, respectively).

The Plant site does not provide any suitable habitat for any of the other special status species (i.e., the Hay's Spring amphipod, the Federal species of concern, and the Virginia state-listed species) discussed in Section 3.4.2. There have been no reported adverse impacts to any of these species due to the Plant while operating at the pre-shutdown level before August 24, 2005. Since Plant operating levels under the DOE Order are no higher than they were under pre-shutdown conditions, adverse impacts to any of the special status species would not be expected.

In order to comply with Section 7 of the ESA, DOE sent letters to FWS and NMFS as part of informal consultation. (See Chapter 6 and Appendix D.) The NMFS by letter dated October 3, 2006, concurred with DOE's determination that continued operation of the Plant under the Orders is not likely to adversely affect any listed species. The FWS by letter dated November 20, 2006, stated that only occasional transient individuals of Federally listed endangered or threatened species are known to exist within the project impact area. Both agencies concluded that no further consultation under Section 7 of the ESA is required.

4.3.5 Waste Management

Potential waste management impacts from the Order include (1) impacts to landfill capacity resulting from changes in the quantity of waste generated and (2) changes in environmental impacts of waste management resulting from changes in solid waste characteristics. Impacts related to solid waste transportation are discussed in Section 4.3.6.

4.3.5.1 Impacts on landfill capacity

Assumptions. In estimating the impacts of operations under the Order on remaining waste capacity in the Mirant Brandywine ash landfill used for disposal of fly ash from the Plant (Section 3.5), DOE made the following assumptions, derived from GB&B Inc. (2005):

- remaining disposal capacity at the beginning of 2005 was 2.07 million yd³ (1.58 million m³);
- ash placed in the landfill has an in-place density of 1.1 ton per yd³ (760 kg per m³); and
- throughout the period of analysis the Chalk Point Generating Plant would generate 206,000 tons (187,000 metric tons) of ash per year, of which 15% would be recycled and 85% would be placed in the Brandywine landfill.

Data and assumptions for pre-shutdown operations. Mirant's records indicate that the Plant sent 113,865 tons (103,297 metric tons) of ash to the landfill during the period January

through August 2005, prior to the events and actions addressed in this SEA (Personal communication between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006). This corresponds to an annual ash generation rate of 170,000 tons (150,000 metric tons) per year, which is somewhat higher than the rate (136,000 tons [124,000 metric tons] per year) used in the GB&B Inc. (2005) analysis.

Assumptions for pre-Order operations. Making the conservative assumption that, on average, pre-Order operations of the Plant during the last three months of 2005 generated fly ash at 20% of the rate recorded for the first eight months of the year, DOE estimated that under pre-Order operating conditions the plant would generate fly ash at a rate of 34,000 tons (31,000 metric tons) per year. (To simplify the assessment of waste management impacts, DOE assumed that under pre-Order operating conditions trona use did not affect the rate of ash generation. This assumption is conservative, in that it minimizes the estimated impacts of pre-Order operations, thus increasing the contrast between the impacts of pre-Order operations and operations under the Order.)

Data and assumptions for operations under the Order. Mirant's records indicate that the Plant sent 28,399 tons (25,763 metric tons) of ash to the Brandywine landfill during the 3-month period March through May 2006 (Personal communication between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006). In estimating the impacts of operations under the Order on landfill capacity, DOE assumed that fly ash was generated at the same average rate from February 2006 until the beginning of June, when the Plant began operating under the ACO. From that time forward the analysis conservatively assumes that under the Order the Plant operates, on average, at pre-shutdown levels, including the temporary extension of the Order to December 1, 2006, and any extension beyond that date.

Impacts. Using the data and assumptions summarized above, DOE estimated total Brandywine landfill waste disposal (from both power plants) during 2005 (prior to the Order) at 269,000 yd³ (206,000 m³), which is somewhat less than the historical annual disposal rate of 278,000 yd³ (213,000 m³) used in the GB&B Inc. (2005) analysis. This value then became the starting point for analysis of the effect of several different Plant operating modes on the remaining capacity and operating life of the landfill, summarized in Table 4.3.5-1.

Pre-shutdown operations. The 2005 analysis by GB&B Inc. projected that with continued operations at then-current (i.e., pre-shutdown) operating levels, the Brandywine ash landfill would be able to continue receiving ash from the Plant and Mirant's Chalk Point Generating Plant until the middle of 2012.

Pre-Order operations. Table 4.3.5-1 indicates that under pre-Order operating conditions, beginning with the date of the Order and continuing indefinitely, the landfill would be able to receive waste from both power plants for approximately the next 9 years, through the middle of 2015.

Operations under the Order and any extension. To indicate the potential range of impacts from operations under the Order and any extension (including the temporary extension through December 1, 2006), Table 4.3.5-1 presents estimates of disposed waste volume and remaining

Table 4.3.5-1. Impact of Plant operations on remaining operating life of the Brandywine ash landfill

Plant operating mode ^a	Disposal rate for Plant fly ash (yd ³ /year) ^b	Estimated full-capacity date for landfill
Pre-shutdown operations ^c	119,000	mid-2012
Plant operates at pre-Order level ^d	31,000	mid-2015
Plant operates in accordance with the Order, without trona injection ^e	varies ^e	late 2011
Plant operates in accordance with the Order (as above), with trona injection ^f	310,000 ^f	early 2010

^a Mirant's Chalk Point Generating Plant is assumed to operate under all scenarios, generating 159,000 yd³ of in-place waste annually. If Chalk Point Generating Plant operated and the Mirant Potomac Plant did not, the estimated full-capacity date for the landfill would be the end of 2017 (GB&B 2005).

^b To obtain the approximate equivalent numerical value in tons/year, multiply by 1.1.

^c These values are from GB&B Inc. (2005).

^d Pre-Order level of operations is conservatively estimated to be equivalent to approximately 20% of pre-shutdown operations.

^e Due to line outage conditions in January 2006, operations in accordance with the Order during that month are assumed to have resulted in waste disposal at the pre-shutdown rate. Operations during February through May are assumed to have resulted in waste disposal at the annual rate of 103,000 yd³/year recorded during March through May (Personal communication between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006). Beginning in June 2006, the Plant is assumed to operate at the pre-August 2005 level, without trona injection, resulting in waste disposal at annual rate of 155,000 yd³/year.

^f Beginning in June 2006, trona injection is assumed to double the quantity of waste requiring disposal.

landfill life for two different assumptions: (1) the Plant operates at pre-shutdown levels, but with no use of trona, after the beginning of June 2006 (since trona is used in operations under the Order, this assumption results in a lower-bound estimate of potential impacts from the Order) and (2) the Plant operates at pre-shutdown levels beginning in June 2006 and trona is injected at a rate which doubles the pre-shutdown rate of solids generation. Trona injection in the Plant can substantially increase ash production; at injection rates necessary to achieve maximum SO₂ removal, trona injection could double or triple the quantity of fly ash waste generated by the Plant (Mirant 2006c). Because trona injection is done only part of the time that the Plant operates and Mirant records of fly ash generation during the period March through May 2006 (Personal communication between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006) indicate that trona use during that period increased fly ash production by approximately 50% over the quantity expected based on coal utilization during the same period, the assumption that trona use doubles the rate of fly ash generation is expected to provide an upper bound on the potential impacts of trona use on landfill capacity. DOE's estimates of the potential impact of the Order on landfill operating life (Table 4.3.5-1) assume that operations

continue indefinitely at pre-shutdown levels, instead of ending when the Order or any extension to the Order expires.

The table indicates that with the level of Plant operations estimated under the Order, but without trona use after June 2006, the landfill's operating life would be about one-half year shorter than projected by GB&B (2005) for pre-shutdown conditions, but about 3.5 years shorter than under pre-Order operations. (Note that this analysis assumes that the ash-generation rate reported in the first 8 months of 2005 would continue, rather than the lower rate assumed by GB&B.) Use of trona would cut almost two additional years off the Brandywine landfill's life expectancy, causing it to reach capacity in a little more than three years.

The assumptions of this analysis are conservative, but the limited landfill life that is estimated to remain if trona injection continues at a high rate may not provide sufficient lead time for siting a new ash landfill. If the Brandywine landfill were to reach capacity before a new ash landfill were sited, Mirant could ship fly ash to a commercial sanitary landfill until a new landfill became available.

Because commercial landfill capacity in the region is very limited (Metropolitan Washington Council of Governments 2001, VDEQ 2002, Harrison 2004, MDOE 2005), ash might need to be transported long distances if it is required to be sent to a commercial landfill licensed for municipal solid waste. Several large privately owned Virginia landfills receive municipal solid waste from outside the local area (Metropolitan Washington Council of Governments 2001). The nearest of these landfills is in King George County, about 60 miles (100 km) by road from the Plant; others are in the Richmond area, more than 100 miles (160 km) from the Plant. If the state regulatory agency allows coal combustion ash disposal in landfills permitted for disposal of construction and demolition debris (in Maryland, these are called "rubble landfills" or "rubblefills"), there are private landfills closer to the Plant (in Lorton, Virginia, and in Prince George's and Baltimore counties in Maryland) that possibly could be used. It has been estimated that the Lorton landfill will reach capacity before 2011 (Harrison 2004), but the state of Maryland has received applications to site several additional commercial rubble landfills (MDOE 2005), giving some assurance that the region will continue to have disposal capacity for construction and demolition waste.

4.3.5.2 Effects of trona use on the environmental consequences of waste management

In addition to increasing the volume of solid waste requiring management, operation of the Plant with trona injection alters the chemistry and physical properties of the fly ash waste, potentially changing the environmental consequences of its management. (Quantities and characteristics of the Plant's bottom ash are not affected by the use of trona.)

Chemical characteristics of Plant fly ash. Reaction of trona (sodium sesquicarbonate; $\text{Na}_2\text{CO}_3 \cdot \text{NaHCO}_3 \cdot 2\text{H}_2\text{O}$) with SO_2 in the exhaust gas results in the formation of solid sodium sulfate compounds (assumed to be Na_2SO_4), along with the release of gaseous CO_2 . The resulting

sodium sulfate is incorporated into the fly ash captured in the Plant's precipitators, together with mineral ash derived from coal combustion and unreacted trona (which is assumed to be dehydrated in the exhaust gas stream, forming sodium carbonate). Because the trona feed rate is typically several times larger than the feed rate calculated to be necessary to react chemically with SO_2 in the air emissions, the fly ash captured in the precipitators contains several times more sodium carbonate than trona reaction products. Although trona use enhances particulate capture in precipitators (Mirant 2006c), thus adding to the volume of fly ash, the increase in Plant fly ash volume that results from trona injection is due almost entirely to incorporation of trona residue into the fly ash. The trona-ash waste stream also can be assumed to include minor amounts of (1) any trace elements found in the raw trona and (2) compounds formed when other gases in Plant emissions react with trona.

Table 4.3.5-2 presents results of chemical analyses of four samples of ash produced in October and November 2005, including two samples produced during Plant operations without trona injection and two samples produced during trona injection. Comparison of the two pairs of analyses illustrates that trona use converts the Plant's fly ash from a largely insoluble mineral ash (oxide percentages of silica and alumina total 84-86% in the pair of samples produced during operations without trona injection) into a mixture of mineral ash and water-soluble carbonates and salts (the high values for sodium and alkalinity in the second pair of samples in Table 4.3.5-2 identify the sodium carbonate component of the ashes produced during trona injection). Trona use increases ash pH (which already is high, indicating an alkaline material) but also greatly increases alkalinity, which is a quantitative measure of the amount of material available to react with acid. Sulfate, which is a very minor component of ash produced without trona injection (first pair of analyses), is a significant fraction of the ash produced with trona (second pair of analyses). With trona use measurements of loss on ignition (a test used to indicate the level of unburned carbon in a sample) increased from 5% and 12% to values of 20% and higher. Trona addition should not affect the amount of unburned carbon in fly ash, so the increased measured values of loss on ignition probably are attributable to volatilization of trona-related constituents. Chloride was not measured, but it is likely that some sodium chloride is included in the ash due to chemical reaction of trona with the small amounts of chlorine present in Plant emissions.

Selenium concentrations are increased approximately 10-fold in the ash produced when trona is used (second pair of selenium in Table 4.3.5-2) compared with ash produced by Plant operations without trona use (first pair of selenium results in Table 4.3.5-2). The source of the increased selenium in the trona ash has not been determined, but it is likely that selenium (a trace constituent in coal that can volatilize during coal combustion) in Plant exhaust gas reacts with sodium carbonate or trona and is incorporated into the fly ash as solid sodium selenate, Na_2SeO_3 . This chemical reaction is used industrially when sodium carbonate (often referred to as "soda ash") is used in the commercial production of selenium metal to isolate selenium from various other compounds and convert it to the sodium selenate form (WebElements 2006). Although selenium might also be present as an impurity in the natural trona used in the Plant, it is not mentioned in published reports about this material (Dyni 1991, 1996).

Table 4.3.5-2. Concentrations of major constituents and trace elements in samples of Plant fly ash resulting from operations with and without trona injection.

Parameter (units)	Ashes produced without trona injection		Ashes produced during high-rate trona injection	
	Load following	Baseline	Low load	Full load
Silica (%)	56.4	59.3	33.2	38.6
Alumina (%)	27.4	26.6	15.4	17.5
Titania (%)	1.4	1.3	0.7	0.9
Iron (as % FeO)	5.6	5.3	3.1	3.4
Calcium (as % CaO)	1.4	1.3	0.8	1.1
Magnesium (as % MgO)	1.4	1.3	0.8	1.1
Potassium (as % KO)	3	2.5	1.3	1.7
Sodium (as % Na ₂ O)	0.34	0.32	39.2	28.3
Sulfate (as % SO ₃)	0.22	0.17	3.4	5.7
pH (pH units)	10.2	10.2	11.1	11.0
Alkalinity (% CaCO ₃ equivalent)	0.55	0.55	39.21	32.4
Lead (mg/kg)	15	15	8.7	10
Arsenic (mg/kg)	47	39	31	26
Barium (mg/kg)	680	660	310	360
Cadmium (mg/kg)	0.29	0.39	0.2	0.28
Chromium (mg/kg)	13	19	7.7	13
Selenium (mg/kg)	1.1	ND ^a	15	11

^a ND = Not detectable

Source: Mirant (Personal communication between A. Wearmouth, Mirant Corporation, and E.D. Smith, Oak Ridge National Laboratory, July 21, 2006)

Measured concentrations of lead, arsenic, barium, and chromium are lower in ash produced during trona operations, probably indicating a dilution effect from the addition of trona components to the mineral ash. Cadmium concentrations are similar in both types of ash. Mercury and silver concentrations are not presented in Table 4.3.5-2 because these metals were below detection limits in all samples.

The ash samples were tested for leachability using the Toxicity Characteristic Leaching Procedure (TCLP) (Personal communication between A. Wearmouth, Mirant Corporation, and E.D. Smith, Oak Ridge National Laboratory, July 21, 2006). The TCLP simulates leaching in the acidic environment of a municipal solid waste landfill and is one of the tests specified under the Resource Conservation and Recovery Act (RCRA) for determining whether a solid waste is a hazardous waste. TCLP extracts were analyzed for lead, silver, arsenic, barium, cadmium,

chromium, selenium, and mercury. These test results do not affect the regulatory status of Plant ash because ash from the combustion of coal, including flue gas emission control waste (such as the trona component of Plant fly ash), is exempt from RCRA regulation as a hazardous waste (40 CFR 261.4).

Barium was the only metal detected in TCLP leachates from the two ash samples produced without trona injection, with concentrations of 0.28 and 0.43 mg/L. Leachates from the two ash samples obtained during trona use had somewhat higher concentrations of barium (0.63 and 0.93 mg/L), but all barium concentrations were below the primary drinking water standard of 1 mg/L, as well as the 100 mg/L threshold for identifying a waste material as a RCRA hazardous waste.

TCLP leachates from both of the ash samples produced during trona injection also contained detectable levels of arsenic and selenium. The measured arsenic concentrations of 1.4 and 1.1 mg/L exceed the primary drinking water standard of 0.05 mg/L, but not the 5 mg/L threshold for identifying a waste material as a hazardous waste. Measured selenium concentrations of 1.1 and 0.77 mg/L also exceed the primary drinking water standard, which is 0.01 mg/L, and the higher measurement exceeds the 1 mg/L threshold for identifying a waste material as a hazardous waste. (As discussed above, however, Plant ash is exempt from RCRA regulation as a hazardous waste.) Sodium selenate (the form in which selenium is likely to be present) is soluble in water, and the presence of sulfate is likely to increase the solubility of both arsenic and selenium.

Implications for waste management operations. Although ash produced during trona injection has reduced pozzolanic activity (Section 2.4.3), it still has significant pozzolanic properties that facilitate its management. Mirant personnel report that trona use does not adversely affect ash workability or its physical stability after placement in the Brandywine ash landfill (Personal communication between D. Cramer, Mirant Corporation, and E.D. Smith, Oak Ridge National Laboratory, July 12, 2006). Thus, there should be no adverse consequences for the emission of windblown dust or for successful stabilization and closure of completed portions of the landfill. Ash produced during trona injection has, however, been observed to be more corrosive than other ash wastes handled at the Brandywine ash landfill (presumably due to the sulfate component), increasing the need for equipment maintenance and possibly accelerating the need for equipment replacement (Personal communication between A. Wearmouth and D. Cramer, Mirant Corporation, and E.D. Smith, Oak Ridge National Laboratory, July 14, 2006).

Fly ash generated during trona use has pozzolanic activity that is too low for most structural uses (TFHRC undated) and contains substantial amounts of sulfate and other soluble constituents that would reduce its suitability for construction use. Therefore, it is unlikely that any Plant fly ash generated during trona use can be beneficially used as a construction material. However, Mirant might be able to find other beneficial uses for this material. For example, due to its high alkalinity, the ash generated during trona production might be a suitable fill material in settings where alkaline material is needed to neutralize acids, such as in waste-site restoration or coal mine reclamation.

Implications for impacts of the Brandywine ash landfill. Leaching of the fly ash produced during trona injection would increase the release of dissolved solids into the landfill leachate that eventually is discharged to Mataponi Creek.

Sodium sulfate, sodium carbonate, and sodium chloride, which are major chemical constituents of the ash produced during trona injection (see discussion above), are all soluble and could be readily released into the leachate. Leachate pH is likely to be higher due to the presence of large amounts of carbonate.

The TCLP test results indicate a potential for the waste produced during trona injection to release the trace constituents selenium and arsenic. The presence of soluble sulfate and carbonate in leachate might increase the solubility and mobility of these or other trace constituents in the fly ash. Because the TCLP test protocol uses acidic leaching conditions, the TCLP test results may not be good predictors of the potential for selenium and arsenic to leach in the alkaline conditions found in the fly ash landfill. Leach testing using “synthetic precipitation” or “synthetic groundwater” would be more reliable than the TCLP for predicting contaminant mobility in the environment of a fly ash landfill.

Modest increases in effluent pH could be beneficial due to buffering of acidity, but there is a possibility of generating a leachate with a pH higher than permitted for discharge. Release of arsenic and selenium to Mataponi Creek could result in adverse impacts to aquatic biota and other wildlife that consume these organisms (Section 4.3.4).

Increases in release of other dissolved solids are not expected to adversely affect creek water quality. Increased concentrations of sodium sulfate would not be expected to affect the creek’s suitability for aquatic life, since sulfate compounds are neither toxins nor nutrients. Any increase in sodium chloride would likely be indistinguishable from background.

If landfill leachate or storm water had unacceptably high levels of pH, selenium, lead, iron, copper, or zinc, the monitoring required under the existing discharge permit for the landfill (Section 3.5) should identify the presence of these contaminants before the water was discharged, thus providing an opportunity to make arrangements to treat the water before discharges occur. Current discharge monitoring does not, however, provide for detection of arsenic, so surface water releases of arsenic could go undetected.

Similarly, the current groundwater monitoring program (Section 3.5) should provide for detection of unacceptably high levels of pH, chloride, sulfate, and several dissolved metals before any substantial migration occurred. However, groundwater is not monitored for either arsenic or selenium, so groundwater releases of these substances could go undetected. Because shallow groundwater in hydrologic settings similar to the landfill site flows primarily to nearby streams, any adverse impacts from undetected groundwater releases of selenium or arsenic would be experienced in Mataponi Creek and its tributaries.

4.3.6 Transportation Resources

The primary impacts to transportation associated with Plant operations are increases in rail and road traffic due to trains and trucks traveling to and from the Plant.

Impacts from traffic increases due to Plant operations are considered in the context of existing traffic conditions. Other ongoing and future actions in the area that generate traffic or affect the capacity of transportation facilities also contribute to cumulative transportation impacts, including increased traffic and noise. Actions that could combine with Plant operations to create cumulative impacts include the 13 background developments that have been identified (Baxter 2006) as increasing automobile and truck traffic in the vicinity of the Brandywine landfill facility and contributing to the exacerbation of existing road traffic problems, especially on Maryland Route 381. (See Section 3.6.2.) The Woodrow Wilson Bridge Project (Section 3.6.2) is the only highway construction and maintenance project in the Virginia or Maryland Department of Transportation databases (VDOT 2006, MDOT 2006) that is likely to contribute to the cumulative impacts of Plant operations. Truck traffic from the Plant that crosses the bridge going to and from the Brandywine facility would combine with the increased traffic, delays, and noise generated by the Woodrow Wilson Bridge Project to contribute to cumulative impacts on transportation.

The following sections discuss transportation impacts for each of the Plant operating scenarios.

4.3.6.1 Pre-shutdown operations

Rail. Under pre-shutdown operations the Plant used about 2,280 tons (2,052 metric tons) of coal per day. Assuming the use of 100-ton (91-metric ton) rail cars, the Plant required about 23 rail car loads of coal per day. This demand could be met with five coal deliveries to the Plant each week using a 40-car train. Because the Plant has its own rail spur and train yard, five 40-car trains per week did not have major impacts on rail traffic or service on the CSX, Inc. main line.

Also, pre-shutdown operations did not have a major impact in terms of wait times for vehicular traffic at the on-grade rail crossing on the George Washington Parkway. Typical daytime rail operations (20-car trains) stopped traffic on the Parkway for ten periods of about 2 minutes each week, while typical nighttime operations (40-car trains) stopped traffic on the Parkway for five periods of about 4 minutes each week (Personal communication between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006).

Road. Under pre-shutdown operations the Plant generated about 470 tons (430 metric tons) of ash per day. Assuming the use of 24-ton (22-metric ton) dump trucks, ash removal required about 28 round trips each weekday from the Plant to the Brandywine facility. These trips had a minor impact in terms of traffic on the local streets used to access the Plant, as the streets have relatively little traffic and operate at a level-of-service at or near “A” (Personal communication between B. Garbacz, Transportation Engineer, City of Alexandria, Virginia, and J.W. Saulsbury, Oak Ridge National Laboratory, May 26, 2006). Similarly, the 28 truck trips attributable to pre-shutdown Plant operations were not a major part of the traffic volume on the major roads between Henry Street and Maryland Route 381 (Table 3.6-1). However,

pre-shutdown operations did contribute to the existing traffic problems on Maryland Route 381 (see Section 3.6.2).

4.3.6.2 Pre-Order operations

Rail. Under pre-Order operations the Plant used about 540 tons (490 metric tons) of coal per day. Assuming the use of 100-ton (91-metric ton) rail cars, the Plant required about 5.5 rail car loads of coal per day. This total demand could be met with one coal delivery to the Plant each week using a 40-car train. Because the Plant has its own rail spur and train yard, one 40-car train per week did not have major impacts on rail traffic or service on the CSX, Inc. main line.

Also, pre-Order operations did not have a major impact in terms of wait times for vehicular traffic at the on-grade rail crossing on the George Washington Parkway. Typical daytime rail operations (20-car trains) stopped traffic on the Parkway for two periods of about 2 minutes each week, while typical nighttime operations (40-car trains) stopped traffic on the Parkway for one period of about 4 minutes each week (Personal communication between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006).

Road. Under pre-Order operations, the Plant is estimated to have generated about 95 tons (86 metric tons) of ash per day. Assuming the use of 24-ton (22-metric ton) dump trucks, ash removal required about five or six round trips each weekday from the Plant to the Brandywine facility. These trips had a negligible impact in terms of traffic on the local streets used to access the Plant, since the streets have relatively little traffic and operate at an level-of-service at or near “A” (Personal communication between B. Garbacz, Transportation Engineer, City of Alexandria, Virginia, and J.W. Saulsbury, Oak Ridge National Laboratory, May 26, 2006). Similarly, the addition of five or six truck trips to the existing traffic volume on the major roads between Henry Street and Maryland Route 381 (Table 3.6-1) represented only a small impact. However, pre-Order operations did contribute to a small extent to the existing traffic problems on Maryland Route 381. (See Section 3.6.2.)

4.3.6.3 Operations under the DOE Order, temporary extension, and potential additional extensions

Rail. Under the Order before the commencement of daily predictive modeling (between December 20, 2005, and June 30, 2006), the Plant is assumed to have used an average of about 1,990 tons (1810 metric tons) of coal per day. Assuming the use of 100-ton (91-metric ton) rail cars, the Plant required about 20 rail car loads of coal per day. In addition, the use of trona required delivery by two rail cars per day. This total demand (about 22 rail cars per day) could be met with four coal/trona deliveries to the Plant each week using a 40-car train. Because the Plant has its own rail spur and train yard, two 40-car trains per week did not have major impacts on rail traffic or service on the CSX, Inc. main line.

Also, operations between December 20, 2005, and June 30, 2006, did not have a major impact in terms of wait times for vehicular traffic at the on-grade rail crossing on the George Washington Parkway. Typical daytime rail operations (20-car trains) stopped traffic on the Parkway for eight periods of about 2 minutes each day, while typical nighttime operations (40-car trains) stopped traffic on the Parkway for four periods of about 4 minutes each night (Personal communication between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006).

Following commencement of daily predictive modeling (on July 1, 2006), including the temporary extension of the Order to December 1, 2006, and any extension beyond that date, the Plant is assumed to operate at a level similar to pre-shutdown operations, but with the addition of trona. Thus, the Plant uses an average of about 2,280 tons (2,050 metric tons) of coal per day. Assuming the use of 100-ton (91-metric ton) rail cars, the Plant requires about 23 rail car loads of coal per day. In addition, the use of trona requires delivery by two rail cars per day. This total demand (about 25 rail cars per day) could be met with five coal/trona deliveries to the Plant each week using a 40-car train. Because the Plant has its own rail spur and train yard, five 40-car trains per week do not have major impacts on rail traffic or service on the CSX, Inc. main line.

Also, following commencement of daily predictive modeling, the Plant is assumed to not have a major impact in terms of wait times for vehicular traffic at the on-grade rail crossing on the George Washington Parkway. Typical daytime rail operations (20-car trains) stop traffic on the Parkway for ten periods of about 2 minutes each week, while typical nighttime operations (40-car trains) stop traffic on the Parkway for five periods of about 4 minutes each week (Personal communication between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006).

Road. Under the Order before the commencement of daily predictive modeling (between December 20, 2005, and June 30, 2006), the Plant is estimated to have generated about 16 to 28 round trips each weekday (using 24-ton trucks) transporting ash from the Plant to the Brandywine facility. These trips had a negligible impact in terms of traffic on the local streets used to access the Plant, as the streets have relatively little traffic and operate at a level-of-service at or near “A” (Personal communication between B. Garbacz, Transportation Engineer, City of Alexandria, Virginia, and J.W. Saulsbury, Oak Ridge National Laboratory, May 26, 2006). Similarly, the addition of 16 to 28 truck trips to the existing traffic volume on the major roads between Henry Street and Maryland Route 381 (Table 3.6-1) represented only a small impact. However, the increase in traffic associated with operations between December 20, 2005, and June 30, 2006, contributed to the existing traffic problems on Maryland Route 381. (See the discussion in Section 3.6.2.)

Following commencement of daily predictive modeling (on July 1, 2006), including the temporary extension of the Order to December 1, 2006, and any extension beyond that date, the Plant is assumed to operate at a level similar to pre-shutdown operations, but with the addition of trona. Because the use of trona can approximately double the amount of ash produced, the Plant generates up to twice as much coal fly ash per day as under pre-shutdown operations (Section

4.3.6.1), requiring up to 56 round trips each weekday from the Plant to the Brandywine facility. Mirant is currently approved to deliver a total of 100 truckloads of ash to the Brandywine facility each weekday from the Potomac River Generating Plant and the Chalk Point Generating Plant combined (Baxter 2006).

Although the estimated level of truck traffic each weekday after July 1, 2006 (56 round trips), exceeds truck traffic under pre-shutdown operations (28 round trips), pre-Order operations (6 round trips), and operations between December 20, 2005, and June 30, 2006 (14 to 16 round trips), it does not appear to have a major impact in terms of traffic on the local streets used to access the Plant, since the streets have relatively little traffic and operate at a level of service at or near “A” (Personal communication between B. Garbacz, Transportation Engineer, City of Alexandria, Virginia, and J.W. Saulsbury, Oak Ridge National Laboratory, May 26, 2006). Similarly, the addition of about 56 truck trips to the existing traffic volume on the major roads between Henry Street and Maryland Route 381 (Table 3.6 1) represents a relatively minor impact in terms of traffic. The increase in traffic associated with operations after commencement of daily predictive modeling is, however, estimated to make a relatively large contribution to the existing traffic problems on Maryland Route 381. (See the discussion in Section 3.6.2.)

4.3.7 Environmental Justice

As discussed in Section 4.3.1, the elevated levels of air pollution from Plant operation that occur under certain conditions are highest very close to the Plant. Because of their proximity to the Plant, under all operating conditions residents of block groups 1 and 2 (Figure 3.7-1) experience higher exposures to air pollution from Plant emissions than residents of block groups 3 and 4. All of the gridded locations where maximum modeled ambient air concentrations occur (as reported in Tables 4.3.1-1 and 4.3.1-2) are located within block groups 1 and 2.

Thus, the populations with the highest exposure to impacts from the Plant are the non-minority and non-low-income populations in block groups 1 and 2. Consequently, the minority and low-income populations in block groups 3 and 4 (Section 3.7) do not experience “disproportionately high and adverse human health or environmental effects” related to air pollutant emissions from the Plant. In addition, DOE has not identified any different or unique ways that these or other minority and low-income populations in the area could be exposed to Plant air pollutants or otherwise affected by the Order or its potential extension. Thus, neither the Order nor any extension to the Order have “disproportionately high and adverse human health or environmental effects ... on minority and low-income populations” as discussed in Executive Order 12898, *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations*.

As discussed in Section 4.3.1, the elevated levels of air pollution from Plant operation that occur under certain conditions are highest close to the Plant. Thus, because of their proximity to the Plant, under all operating conditions residents of block groups 1 and 2 experience higher air pollution from Plant emissions than residents of block groups 3 and 4. Consequently, the minority and low-income populations in block groups 3 and 4 do not

experience “disproportionately high and adverse human health or environmental effects” related to air pollutant emissions from the Plant. In addition, these populations do not have different or unique ways of being affected by the Order or its potential extension.

5. ALTERNATIVES FOR FUTURE DECISION-MAKING

The DOE Order, as extended, expires on December 1, 2006. Before December 1, 2006, DOE will decide whether to allow the Order to expire, extend the Order, or take some other action, such as extending the Order with mitigation measures.

5.1 Allow the Order to Expire

As stated in the Order, Pepco's new 230-kV transmission lines are expected to provide a high level of electric reliability to the Central D.C. area even in the absence of production from the Plant. However, these new lines are not expected to be complete until the summer of 2007. DOE cannot speculate how Mirant would operate if DOE did not extend the Order; however, allowing the Order to expire would likely place the Central D.C. area in risk of a potential blackout.

It is difficult to specify the risk of death or health injury associated with blackouts because of the lack of statistical studies on such risk. However, blackouts can cause, and historically have caused, significant health and environmental impacts.

Blackouts create multiple public health problems that can lead to new or exacerbated injury or death. During hot weather blackouts can result in increased deaths, due to loss of air-conditioning or cooling ventilation. For example, 232 deaths were reported in the Midwest in the summer of 1999 during an extreme heat wave that also included a series of power disturbances; the majority of the deaths were attributable to elderly individuals without access to air-conditioning (Palecki and Changnon 1999). Blackouts can also cause significant problems for people with existing illnesses. During the Midwest/Northeast blackout of August 2003 paramedics from Passaic Beth Israel hospital had to respond to four times the usual number of calls, many involving respiratory ailments for patients whose batteries on home respirators had expired and for electronic breathing aids that went dead (WNBC 2003a).

Blackouts can also cause impacts to drinking water supplies and water bodies. The Midwest/Northeast blackout of August 2003 cut water service to 1.5 million people in Cleveland and caused officials in Detroit to warn residents to boil their water until the supply could be tested for potential bacteria (Water Quality and Health Council 2004). Because electricity powers pumps that push water through a city's water system, blackouts can cause the pressure in water pipes to drop, leaving the system open to bacteria entering the water supply. In addition, the discharge of sewage from treatment plants that run on electricity can cause environmental damage to water bodies. As recently as May 19, 2006, a 3-hr power failure at the Blue Plains Wastewater Treatment Plant in Washington, D.C. resulted in 17 million gallons (64,000 m³) of raw untreated sewage being spilled into the Potomac River (Cohn 2006).

Blackouts also cause injury and death from fires (e.g. due to burning of candles), use of unvented portable emergency generators, accidents, and criminal activity. In the July 1977

blackout in New York City fires killed three, and one store owner shot and killed an armed looter (TIME 1977). Hundreds were also injured during widespread looting and other criminal activity in the July 1977 blackout. In a July 2006 blackout in Missouri that affected 150,000 people, a utility worker died after touching downed power lines, and another man died from burns while he tried to fix a generator he was using in his home (Associated Press 2006). In addition, during the Midwest/Northeast blackout of 2003 two people succumbed to carbon monoxide fumes from a gas generator aboard the boat they had been sleeping in overnight (WNBC 2003b).

5.2 Extend the Order as Currently Written

Impacts associated with extending the Order until either June 30, 2007, or December 31, 2007 (assuming a delay in installation of the new transmission lines), are assessed in Chapter 4. Extension of the Order until either date would result in increased impacts as compared to the Plant's "pre-Order" operating mode, but not the Plant's "pre-shutdown" operating mode. As presented in Chapter 4, impacts resulting from SO₂ emissions would be lower than under the pre-shutdown mode, while impacts resulting from trona use would be higher than under the pre-shutdown mode, and levels of other impacts would be similar to those from pre-shutdown operations.

5.3 Extend the Order with Mitigation Measures

Impacts of Plant operation under an extension of the Order could be mitigated by various alternatives including: (1) requiring Mirant to improve Plant operations and pollution control measures, (2) requiring Mirant to reduce exposure to pollutants to workers and nearby residents, (3) managing the demand for electricity in the Central D.C. area, (4) using alternative sources for generating electricity, and (5) expediting the installation of additional transmission lines.

5.3.1 Improve Plant Operations and Pollution Control Measures

- Require Mirant to store enough trona at or near the Plant to achieve 80% removal of SO₂ emissions for the full duration of any planned line outages. Mirant's experiments with trona indicate that this level of sulfur removal can be achieved. While Mirant has installed trona units on all five boilers, Mirant does not maintain sufficient trona on site or nearby to reduce emissions by 80% under high power operations for the duration of planned line outages.
 - Requiring Mirant to store sufficient trona at the Plant could help to ensure the logistical feasibility of achieving 80% removal of SO₂ emissions during a planned line outage, pursuant to the ACO. This could result in decreased modeled emissions

and any associated health effects. The quantity of trona available to Mirant may be limited, however, or it may take more time to increase current storage space at or near the Plant than required to install the two new transmission lines. DOE can consider working with EPA to monitor the ability of Mirant to gain and store enough trona for the Plant to achieve 80% SO₂ removal.

- Require that during non-outage situations Mirant operate the Plant at the minimum level of power generation that would maintain all units in a state in which they would be available to produce full power within a few hours of a line outage. Based on information provided by Mirant, minimum operation would require each baseload unit to operate 20 hours per day at minimum power (about 30 MW) and 4 hours at maximum power (about 105 MW). Similarly, the load-following or cycling units would need to operate 8 hours per day at minimum power (30 MW) and 4 hours at maximum power (88 MW).
 - This would reduce overall operation of the Plant and, therefore, reduce emissions and any associated health effects. DOE considered this operating mode before issuing the Order, but determined that it is not feasible because the baseload units at the Plant are designed for operation at high power levels and cannot sustain low levels of operation for a long period of time without damage.
- Require Mirant to increase the height of the Plant's exhaust stacks in order to create conditions conducive to better dispersion of emitted pollutants.
 - Taller stacks would reduce modeled air quality impacts of plant operations. The taller stacks would be visible at a greater distance and may also result in adverse visual impacts for neighbors of the Plant. Issues related to stack height increase are under the jurisdiction of the Federal Aviation Administration (FAA), which has granted Mirant permission to raise the stacks by 50 ft (15 m).

5.3.2 Reduce Exposure to Pollution

- Require Mirant to notify nearby residents when they would be potentially affected by a modeled NAAQS exceedance.
 - DOE is not able to estimate what people would do with such information and whether any decrease in health effects would occur. However, DOE can consider requiring Mirant to post daily when residents would be potentially affected by a modeled NAAQS exceedance during a line outage.

- DOE will post Mirant's monthly reports to EPA (as required by the ACO), as they become available to DOE, on DOE's website containing information related to the Plant. Such monthly reports would notify nearby residents of the results of monitored data, thereby allowing nearby residents to assess the likelihood of future exposure to an actual NAAQS exceedance.
- Pepco is filing monthly progress reports on the status of Pepco's new transmission lines and corresponding planned outages with FERC (FERC docket number EL05-145-000). Nearby residents can access Pepco's monthly reports through FERC's elibrary system at <http://www.ferc.gov/docs-filing/elibrary.asp> (search for FERC docket number EL-05-145-*).

In addition, pursuant to the December 20, 2005, Order, Pepco is required to give advance notice of any planned outage and the estimated duration of any such outage to DOE. DOE will post any advance notice received from Pepco on DOE's website containing information related to the Plant (<http://www.oe.energy.gov/permitting/372.htm>).

Therefore, nearby residents should be aware of planned line outage situations when the Plant is directed to produce power (up to full capacity) as directed by PJM.

- Require Mirant to provide the people who live in areas that would be affected by modeled exceedances of NAAQS during planned line outage situations the reasonable cost of moving to alternate locations until the threat of an exceedance is over if such people so choose.
 - Implementing this would involve several practical difficulties, such as determining the number of people who would be affected by a modeled exceedance, and whether relocation would be an appropriate response.
 - DOE believes that this may not be an appropriate use of its authority under Section 202(c) of the Federal Power Act (FPA) under these circumstances.
- Require Mirant to monitor outdoor levels of PM on the Plant site and provide suitable breathing protection for those working in high PM areas.
 - DOE can consider consulting with EPA about the need for PM monitoring. Determining the need for or type of suitable breathing protection is too speculative at this time.

5.3.3 Manage the Demand for Electricity in the Central D.C. Area

- Require the D.C. Public Service Commission (DCPSC) to develop a plan for reducing electrical demand in the Central D.C. area.
 - Reducing electrical demand in the Central D.C. area would reduce the need for operation of the Plant. However, the DCPSC and Pepco do not currently have a formal plan to reduce electrical demand in this area. Developing a plan would require rulemaking procedures, and implementing the plan would require infrastructure changes that may well take more time than required to install the new transmission lines. However, DOE has had several discussions with DCPSC encouraging DCPSC's efforts to reduce electrical demand in the Central D.C. area. DCPSC has informed DOE that:
 - DCPSC has given approval to Pepco to install "smart meters" in 2,250 homes as part of an effort to investigate how demand can be reduced in peak and other critical times.
 - DCPSC is currently in discussions with fellow state public service commissions in the Mid-Atlantic area and with PJM on how to improve demand response and related distributed energy resources.
 - A DCPSC commissioner is currently chairing the Mid-Atlantic Distributed Resources Initiative (<http://www.energetics.com/madri/>). DOE is currently providing technical advisory services and funding for facilitation efforts for this Initiative.
 - DOE can continue to encourage DCPSC to pursue demand-response initiatives in the Central D.C. area as in previous Orders.
- Order the development of specific, emergency load reduction programs to compensate for an unexpected loss of electricity generation or transmission capacity. For example, DOE could require emergency load shedding or load cycling for Federal and/or D.C. government buildings and/or other facilities during electrical emergencies.
 - Emergency load shedding or load cycling would reduce the need for operation of the Plant. DOE's Federal Energy Management Program is pursuing opportunities for energy management within the Federal government, both within and outside of emergency situations. Most recently, DOE and the General Services Administration held a workshop on April 26, 2006, on potential demand-response opportunities that

was attended by the majority of Federal electricity customers. The workshop educated Federal electricity customers on the reliability problems in the Central D.C. area and offered DOE technical assistance for demand-response initiatives.

5.3.4 Use Alternative Sources for Generating Electricity

- Require installation of temporary or back-up electricity generating equipment at specific facilities or government agencies to eliminate the need for the Mirant Plant.
 - Installation of temporary or back-up electricity generating equipment would not likely generate enough power to eliminate the need for the Plant. Alternative sources of electricity sufficient to eliminate the need for one or more units at the Plant could not be brought on line before the additional 230-kV power lines have been brought into service.
- Encourage Federal agencies in the Central D.C. area to operate on alternative sources of electricity, to reduce their peak electricity demand, or to develop a generating capability. For example, heating plants operated by the General Service Administration could be modified to cogenerate both heat and electricity, and essential government facilities could become capable of independently generating their own electricity in emergencies.
 - Alternative sources of electricity could reduce the need for the Plant and were discussed at DOE's April 2006 workshop described above. However, alternative sources of electricity sufficient to replace the Plant or eliminate the need for one or more units at the Plant could not be brought on line before the additional 230-kV power lines have been brought into service.

5.3.5 Expedite the Installation of Additional Transmission Lines or Encourage the Use of Other Existing Lines

- Expedite the installation of the two 230-kV transmission lines that Pepco is currently working on.
 - DOE has evaluated Pepco's construction schedule to make sure it is as efficient as possible. DOE can continue to monitor the construction and outage schedule to ensure, as much as possible, that the construction process remains on schedule and that any planned outages are essential. Pepco notified DOE on September 7, 2006, that the expected installation date of the new 230-kV lines is now June 21, 2007, instead of July 1, 2007.

- DOE can provide assistance to Pepco in expediting the installation of the new 230-kV lines that is requested by Pepco and that is practical and feasible. For example, at Pepco's request DOE met with Pepco representatives in March 2006 to discuss ways that DOE could help with the NEPA process for Pepco's proposed route for the new 69-kV lines to the Blue Plains Wastewater Treatment Plant (which partially fall on National Park Service land). The new 69-kV lines became operational on July 15, 2006.
- Encourage Pepco to construct additional new transmission lines, for example, from other plants in close proximity to the Central D.C. area, namely the Benning Road or Buzzard Point plants, to supply the power currently provided by the Plant.
 - Pepco already uses the power from these sources for other customers. Obtaining additional rights-of-way to construct new transmission lines would not be feasible in the time period required to solve the immediate reliability issues in the Central D.C. area.
- Encourage the use of additional transmission lines along existing corridors. Existing transmission lines enter the D.C. area from the north and south along, for example, railroad rights-of-way of the National Railroad Passenger Corporation ("AMTRAK") and CSX Corporation.
 - As described in Pepco's April 13, 2006, filing to DOE, although use of the existing transmission lines on the AMTRAK and CSX rights-of-way would reduce the need for the Plant in the Central D.C. area, the lines are already being used by Pepco. Adding additional lines along the same corridor would take more time than required to install the new 230-kV transmission lines already planned and under development.
- Encourage the use of currently existing, but inactive, transmission lines, such as the 69-kV circuits between Buzzard Point and the Plant.
 - As described in Pepco's April 13, 2006, filing to DOE, Pepco refurbished three 69-kV circuits between Buzzard Point and the Plant in 2004 to provide emergency back-up service, which would be used to restart the Plant and help the restoration process for any blackout of the Central D.C. area. These circuits cannot be energized under normal operating conditions because they are of small capacity and would overload quickly upon the failure of one of the existing 230-kV transmission circuits or the Plant; thus, their use would not provide an increase in reliability.

6. REGULATORY CONSULTATION AND COMPLIANCE

Under Section 7 of the Endangered Species Act (ESA) Federal agencies must consult with the Fish and Wildlife Service (FWS) or the National Marine Fisheries Service (NMFS) regarding actions that they may undertake that could adversely affect species and habitats protected under the Act. In order to comply with this requirement, DOE sent letters to FWS and NMFS as part of informal consultation describing the species that were likely to occur near the Plant and requesting concurrence from FWS and NMFS that the operation of the Mirant Potomac River Generating Station under the terms of the DOE Orders would not adversely impact Federally listed or proposed threatened or endangered species or designated or proposed critical habit. (See Appendix D.)

The responses from FWS and NMFS, also included in Appendix D, are discussed in Section 4.3.4.4.

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APPENDIX A

DOE Emergency Orders

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United States of America
Department of Energy

District of Columbia Public Service Commission)

Docket No. EO-05-01

Order No. 202-05-3

I. Summary

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, a shortage of facilities for the transmission of electric energy and other causes, and that issuance of this order will meet the emergency and serve the public interest. Therefore, Mirant Corporation and its wholly owned subsidiary, Mirant Potomac River, LLC (collectively referred to herein as Mirant), are hereby ordered to generate electricity at their Potomac River Generating Station (the “Plant”) pursuant to the terms of this order.

II. Procedural History

On August 19, 2005, Mirant submitted to the Virginia Department of Environmental Quality (DEQ) a computerized emissions modeling study Mirant had conducted of its Plant that indicated that emissions from the Plant caused or contributed to significant localized exceedances of the National Ambient Air Quality Standards (NAAQS).¹ Also on August 19, 2005, DEQ issued a letter to Mirant which requested “that Mirant *immediately* undertake such action as is necessary to ensure protection of human health and the environment, in the area surrounding the Potomac River Generating Station, including the potential reduction of levels of operation, or potential shut down of the facility.” (emphasis in original). The letter asked Mirant to provide DEQ with a summary of the actions taken and the progress toward eliminating NAAQS exceedances by August 24, 2005. At midnight on August 21, 2005, Mirant reduced production of all units at the Plant to their minimum load, and at midnight on August 24, 2005, Mirant shut down all five of the generating units at the Plant.

On August 24, 2005, the District of Columbia Public Service Commission (DCPSC) filed an *Emergency Petition and Complaint* with both the United States Department of Energy (DOE or Department) and the Federal Energy Regulatory Commission (FERC or Commission) pursuant to the FPA. The DCPSC requested the Secretary of Energy to find that an emergency exists under section 202(c) of the FPA and to issue an order directing Mirant to continue

¹ The Clean Air Act, 42 U.S.C. § 7401 *et seq.*, authorizes the United States Environmental Protection Agency (EPA) to establish NAAQS, 42 U.S.C. §§ 7408-7409, and states that it is the responsibility of the states and local governments for assuring that they are attained, 42 U.S.C. §§ 7401(a)(3) and 7416.

operation of the Plant. The basis for the petition was that the shutdown of the Plant “...will have a drastic and potentially immediate effect on the electric reliability in the greater Washington, D.C., area and could expose hundreds of thousands of consumers, agencies of the Federal Government and critical federal infrastructure to curtailments of electric service, load shedding and, potentially, blackouts.” The DCPSC requested that the Commission issue a similar order under sections 207 and 309 of the FPA. Numerous parties filed interventions and comments in response to DCPSC’s emergency petition, as well as subsequent comments and responses.² Further, both FERC and DOE issued information requests to Mirant, the Potomac Electric Power Company (PEPCO), the company responsible for supplying electricity to retail customers in the District of Columbia, and PJM Interconnection, LLC (PJM), the grid operator responsible for the administration of the bulk power grid and electricity market in the region.³ In addition to the DCPSC petition proceedings, DOE has hosted and participated in numerous conference calls and meetings to gather information on the shutdown of the Plant and its effect on the reliability of D.C.’s electricity system.⁴

III. Background

The coal-fired Mirant Plant, which began operation in 1949, is located in Alexandria, Virginia, and is capable of producing 482 megawatts of electricity primarily for delivery to Washington, D.C. The Plant consists of five generating units, two of which are cycling units that range in output from 35 MW to 88 MW, and three of which are baseload units that range in output from 35 MW to 102 MW. It is one of only three sources of electricity that serve the central business district of the District of Columbia, many federal institutions, the Georgetown area in D.C., as well as other portions of Northwest, D.C., and the District of Columbia Water and Sewer Authority’s Blue Plains Advanced Water Treatment Plant, the largest wastewater

² Several of these filings were only made in the FERC docket and not in DOE’s docket. Even though a number of filers did not submit their comments in the DOE docket, the Department has, in the interest of rendering an appropriate and fully informed determination, reviewed all the filings in the FERC docket for any pertinent facts that will assist the Department in making its decision. Also, to the extent the filings contained analysis or legal arguments pertaining to the Department’s 202(c) authority, they have been considered in the Department’s decision making process.

³ The data submitted contained Critical Energy Infrastructure Information and was submitted in both confidential and redacted versions, as defined in FERC’s rules at 18 C.F.R. § 388.13. All information contained in this order is from public filings in the DOE and FERC dockets.

⁴ The Administrative Procedure Act’s prohibitions on ex parte communications in an adjudicatory proceeding, 5 U.S.C. § 557(d)(1), do not apply to DOE’s 202(c) proceedings, because section 202(c) explicitly authorizes the Department to issue a 202(c) order “either upon its own motion or upon complaint, with or without notice, hearing, or report. . .” 16 U.S.C. § 824a(c).

treatment plant in the world.⁵ The other two sources are two 230 kV lines that deliver electricity from other generating sources in the regional electric grid operated by PJM. Although there are other generating units in close physical proximity to the Central D.C. area, (e.g., the Benning Road and Buzzard Point generating facilities, which are dual-fueled oil and natural gas generating power plants, owned by PEPCO) there are no transmission lines that would allow delivery of power from these other units to reach the Central D.C. area. With regard to the sources of power that serve the Central D.C. area, PEPCO owns and operates the transmission lines, and PJM determines electricity demand.

Although Mirant shut down all of the Plant's generating units on August 24, 2005, it has since restarted unit number one which, the Department understands, is currently operating. Mirant is operating the unit on an 8/8/8 basis --- that is, in any given twenty-four hour period, the unit runs for eight hours at its maximum level of 88 MW, eight hours at its minimum level of 35 MW, and has eight hours when it does not run. DOE has been informed that both EPA and DEQ acknowledge that the operation of this unit in this manner does not result in any NAAQS exceedances. In addition, DOE understands that Mirant is taking other steps to increase production at the Plant in a manner which will be acceptable to DEQ and EPA.

PEPCO has applied to the DCPSC to construct two new 230 kV lines that would supply electricity to the Central D.C. area. In the same application, PEPCO has proposed building two new 69kV lines to supply the Blue Plains wastewater treatment plant. PEPCO proposes having the two 69 kV lines installed by the summer 2006 peak season, and the two 230 kV lines installed in 18 to 24 months. The two existing 230 kV lines that supply the Central D.C. area would need to be temporarily taken out of service sequentially in order to connect the new lines to the Central D.C. area. Once completed, these lines apparently would provide a high level of electric reliability in the Central D.C. area, even in the absence of production from the Plant.

IV. Discussion

A. Reliability Issues

The Department has conducted an independent analysis of the electricity reliability situation in the Central D.C. area and has analyzed the Plant's role in ensuring a sufficiently reliable supply of electricity to that area. DOE's analysis was conducted by the Department's Oak Ridge National Laboratory. Under North American Electric Reliability Council standards, at a minimum, the power system must carry at least enough contingency reserves of electricity to cover the most severe single contingency. The standards require that an area's system always be operated with sufficient reserves to compensate for the sudden failure of the area's most important single generator or transmission line.

⁵ For purposes of this order, the area supplied with electricity by these three sources will be referred to as the "Central D.C. area," and the retail customers in this area will be referred to as the "Central D.C. area customers."

Based on the fact that the Central D.C. area has only three sources of supply, the Plant and the two 230 kV transmission lines, the Department's analysis concludes that in order to maintain a minimally reliable electric power system, the Plant must be available to run when one of the 230 kV lines is out of service, because if the remaining line failed there would be no other source of electricity to serve the Central D.C. area load. In addition, the analysis concludes that if one of the 230 kV lines failed unexpectedly, enough generation must be started as rapidly as possible so as to be able to serve all of the Central D.C. area load as a contingency reserve in the event the other line were to fail. The analysis also indicates that the Plant should be operated in such a way as to minimize the amount of time needed to bring it into production.

PEPCO has asserted that:

Absent the generating capacity of the Plant, if the two 230 kV transmission circuits into the [Central D.C. area] fail, there will be a blackout in much of the District of Columbia until the circuits are repaired or the Plant's generators are restarted and can operate at a level that matches load. All electric customers in Georgetown, Foggy Bottom and major portions of downtown Washington will be affected. The affected customers will also include Blue Plains wastewater treatment plant. It is PEPCO's understanding that within 24 hours of the loss of electric supply, Blue Plains will have no option but to release untreated sewage directly into the Potomac River, which would result in a significant adverse impact to human health, aquatic wildlife and other environmental resources. Affected customers will also include numerous hospitals, schools, universities, commercial buildings, and residential customers. Importantly, numerous federal facilities will lose power, including those critical to the security, safety, and welfare of the whole country, such as the FBI, the Justice Department, the State Department, the Federal Emergency Management Agency, the Department of the Interior, and the Department of Energy to name but a few.⁶

No commenter has disputed these statements by PEPCO, and they have been generally corroborated by DOE's own independent analysis; therefore, DOE will accept them as correct statements of fact. Further, the 230 kV lines do go out of service on occasion; since 2000, there have been 34 one-line outages for maintenance, and seven occasions where one of the lines has tripped unexpectedly. DOE has been informed that, prior to 2000, there were two occasions when both of the lines failed simultaneously.

B. Environmental Issues

Some commenters have asserted that the renewed operation of the Plant would result in NAAQS exceedances and a violation of the Clean Air Act, and that DOE could not issue a 202(c) order which would contravene the Clean Air Act (42 U.S.C. §§ 7401-7626). In response to this assertion, DCPSC, PEPCO and PJM contend that there were no actual monitored

⁶ See Potomac Electric Power Company's Leave to Answer and Answer to Comments, FERC Docket No. EL05-145-000 at pages 2 & 3 (September 9, 2005).

exceedances of the NAAQS at the Plant during operation, and that operation of the plant at full power does not exceed the emissions limits contained in the Plant's operating permit and therefore the operation of the Plant pursuant to a DOE order would not violate the Clean Air Act. EPA has shared information with DOE regarding NAAQS modeled results and other environmental issues at the Plant. In response to the environmental concerns raised, this order seeks to minimize, to the extent reasonable, any adverse environmental impacts. Should EPA issue a compliance order directed to operation of the Plant, DOE will consider whether and how this order should conformed to such order.

Another assertion raised is that DOE cannot issue an order without complying with the National Environmental Policy Act (NEPA), 42 U.S.C. § 4321 *et seq.* Responders to that assertion stated that NEPA review requirements do not apply because any order would merely require the Plant to operate in the manner and at the level it has historically operated, and thus is not a "major federal action" triggering NEPA. In addition, responders assert that "...the emergency nature of the relief sought in this case permits the [the Secretary] to act without conducting a NEPA analysis, even if it were required."⁷ DOE has determined that the emergency circumstances here make it necessary to take action without performing a NEPA analysis. Indeed, in order for an order under FPA section 202(c) to be issued at all, the Secretary of Energy must determine that an emergency exists, and I have made that determination here. DOE has consulted with CEQ about alternative arrangements pursuant to 40 C.F.R. § 1506.11.

C. Other Issues

Commenters opposed to the issuance of a FPA section 202(c) order cited *Richmond Power & Light v. FERC*, 574 F. 2d 610 (D.C. Cir. 1978) as imposing a limit on the Secretary's authority to make an emergency finding under section 202(c). In *Richmond*, the New England Power Pool (NEPOOL) petitioned the Federal Power Commission (the Secretary's predecessor in exercising section 202(c) authority) for an order pursuant to FPA section 202(c) to have utilities east of the Mississippi River with excess electric generating capacity supply NEPOOL with that excess capacity. The request was based on fears of an oil shortage due to the 1973 Arab oil embargo. The Commission responded by holding a conference and a series of meetings which resulted in an agreement among the purchasing, transmitting and supplying utilities and participating state regulatory commissions. As a result of the agreement, NEPOOL moved to withdraw its petition, which the Commission allowed. Richmond Power & Light Company challenged the decision to allow the withdrawal and the court found that the Commission did not abuse its discretion in declining to issue an order under section 202(c), but rather settling on the temporary-voluntary agreement program reached by the interested parties. Instead of limiting its

⁷ District of Columbia Public Service Commission Answer to Motion of the Virginia Department of Environmental Quality at page 24 (October 26, 2005), FERC Docket No. EL05-145-000. *See also* Answer of Potomac Electric Power Company and PJM Interconnection, LLC at page 18, (October 13, 2005), FERC Docket No. EL01-145-000.

reach, *Richmond* underscores the discretionary nature of the Secretary's authority under section 202(c).⁸

Another case asserted to limit the Secretary's authority to issue an order under section 202(c) was *National Fuel Gas Supply v. FERC*, 909 F2d 1519 (D.C. Cir. 1990). In that case, National Fuel applied under section 7 of the Natural Gas Act (NGA), 15 U.S.C. § 717 *et seq.*, for a certificate of public convenience and necessity to allow it to make interruptible sales of natural gas. The Commission imposed a condition that National Fuel accept a blanket transportation certificate to provide open access transportation. The court ruled that the Commission was improperly using a NGA section 7 certificate condition in place of an individual or generic proceeding under section 5 of the NGA. The Department does not see the relevance of *National Fuel* here. I am using section 202(c) of the FPA for precisely the type of situation contemplated by section 202(c) of the FPA.

V. Decision

Section 202(c) of the FPA vests in the Secretary of Energy the authority to issue an order when "an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of the fuel or water for generating facilities, or other causes...." 16 U.S.C. § 824a(c). DOE's regulations acknowledge that "[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency as contemplated by these regulations." 10 C.F.R. § 205.371.

I find that in the circumstances presented here, an emergency exists that justifies the issuance of a section 202(c) order. My determination is not based on any single factor, but on the combination of all relevant facts and circumstances. In particular, I find that an emergency exists because of the reasonable possibility an outage will occur that would cause a blackout, the number and importance of facilities and operations in our Nation's Capital that would be potentially affected by such a blackout, the extended number of hours of any blackout that might in fact occur, and the fact that the current situation violates applicable reliability standards.

⁸ The facts in *Richmond* and in the current situation are very different. *Richmond* dealt with a wide regional or even national energy shortage situation, while we are considering electricity reliability in a discrete geographic area. The facts here more closely resemble those considered by the Federal Power Commission in *City of Cleveland, Ohio v. Cleveland Electric Illuminating Company*, 47 FPC 747 (1972). In that case, the City of Cleveland petitioned the Commission pursuant to section 202(c) to order an interconnection with Cleveland Electric Illuminating Company to provide services during shortages caused by outages of the City of Cleveland's generating facilities, or delays getting generation on line. The Commission found that the City of Cleveland had an emergency due to periodic shortages of generating facilities caused by outages and ordered the establishment of a 69kV temporary emergency interconnection between the electric systems of the City and Cleveland Electric Illuminating. Similarly, here DOE is ordering the Plant to provide electricity in certain limited situations.

More specifically, if the Mirant plant is not available to generate electricity and one of the two transmission lines serving the Central D.C. area goes out of service, the Central D.C. area would be served by only one transmission line. Should that remaining line fail for any reason, a blackout would occur in the Central D.C. area, potentially for an extended period of time. In fact, if one or both of the transmission lines could not be brought back into service immediately and the only source of energy for the Central D.C. area was the Mirant Plant, in the absence of today's order it would take several hours at a minimum to bring the Plant into full operation.

The outage of one of these two lines is not merely a theoretical possibility. On Friday, December 16, 2005, PJM informed DOE that on the previous night, "one of the two circuits critical to providing service to the District tripped. Continued [electric] service to certain load within the District was at that time entirely dependent on the remaining circuit." As a result, PJM requested dispatch of a second generating unit at the Plant, but Mirant refused to do so. PJM informed DOE that "service was not interrupted because load was low and the remaining circuit performed without incident." Fortunately, full service to the line that had tripped was restored by the morning of December 16. Nonetheless, there can be no assurance that the Central D.C. area will be so lucky next time, either with respect to the timing of the event, the operation of the second transmission line, or the ability to bring the first transmission line back into service.

Furthermore, it is periodically necessary for an outage to occur on one of the transmission lines because of the need to perform maintenance. In fact, maintenance is scheduled on one of the lines in the next few weeks. Thus, as occurred on the night of December 15, 2005 and as will certainly occur again in the future, if the Mirant Plant is not made operational Central D.C. will find itself relying solely on one transmission line. The duration of an outage can range from up to several days (for maintenance) or even longer (up to weeks) if the outage of a line is due to a major equipment failure. Throughout such a period, if the Plant is not fully operational a blackout in Central D.C. is only one step away, i.e., if an event should occur that causes the second line to fail. Such a blackout could last for hours or days.

I recognize that, if past experience is any guide, the simultaneous failure or outage of both transmission lines serving the Central D.C. area is not a high probability. While this event has occurred in the past, it has not happened often. Moreover, the recent tripping of one circuit does not in itself dictate the existence of an emergency justifying issuance of a 202(c) order.

The facilities and functions that would be adversely affected by an extended blackout in this instance, however, is an important consideration. The Central D.C. area includes offices, facilities and operations involved in all three branches of government, and that are critically important to the Nation's national security, law enforcement and regulatory functions. The Central D.C. area also includes hundreds of thousands of residents and workers, and all manner of public safety and protection facilities, including hospitals, police, and fire facilities. Moreover, DOE has been informed that within 24 hours of a blackout in the Central D.C. area, untreated sewage from the Blue Plains Wastewater Treatment plant would be discharged into the Potomac River.

Finally, it is noteworthy that a blackout in the Central D.C. area not only would affect critically important facilities and operations, it could last for an extended period. Depending on the reason for the outage of the transmission lines, the lack of service on those lines accompanied by the lack of generation by the Plant could result in a large portion of the District of Columbia being without electricity for a period that could last hours or days. At the very least, if the two transmission lines were made unavailable with no advance notice and the only source of electricity for the Central D.C. area was the Mirant plant, in the absence of today's order DOE understands it would take at least 28 hours, and likely longer, to bring the Plant into full operation, during which time all or a substantial part of the Central D.C. area would be without electric power. The results would be hardship and physical risk to hundreds of thousands of persons from loss of heat, elevator outages, medical equipment failure and numerous other causes. In addition, critical portions of the nation's government would also be severely impacted, with resulting adverse effects on a national scale.

Of course, the fact that the Department did not act immediately on the DCPSC petition does not argue against my finding that an emergency currently exists. After the petition was filed, DOE took several weeks to gather the relevant information, consider the facts, talk with environmental regulatory authorities, and develop an order that balanced the appropriate considerations. As explained in the text of this order, the current facts fully justify my finding that an emergency exists and that this order will meet that emergency. There certainly is nothing in the Federal Power Act that requires me to wait until a blackout actually has occurred, lives are put in jeopardy, and a significant disruption of National government functions already has happened before exercising my section 202(c) authority.

Accordingly, and based on all of the facts and circumstances, I find that an emergency exists justifying the issuance of this order under Federal Power Act section 202(c).

After finding the existence of an emergency, DOE has the authority, "either upon its own motion or upon complaint, with or without notice, hearing, or report, to order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest." 16 U.S.C. § 824a(c). The statute gives the Secretary of Energy broad discretion to fashion the terms of an order that will, in the Secretary's judgment, "best meet the emergency and serve the public interest." Based on the circumstances described above in this order, I hereby direct Mirant to generate electricity at the Plant pursuant to the terms of this order.

While I am issuing this order to help ensure a reliable supply of electric energy to the Central D.C. area, I am cognizant of the concerns that have been expressed concerning the potential adverse environmental consequences of operating the Plant, and of the national interest in attainment of the NAAQS that have been established under the Clean Air Act. Ordering action that may result in even local exceedances of the NAAQS is not a step to be taken lightly. However, it would not be reasonable for the Department of Energy to stand by and take no positive action on the DCPSC petition, even though the Central D.C. area is in danger of an extended blackout and the Department and private parties have available to them the legal and operational tools to prevent such a blackout from occurring. In this order, I have sought to harmonize those interests to the extent reasonable and feasible by ordering Mirant to operate in a

manner that provides reasonable electric reliability, but that also minimizes any adverse environmental consequences from operation of the Plant.

DOE expects that the DCPSC, having sought an emergency order, will take such actions as are within its authority to provide adequate and reliable electric service for the Central D.C. area including, for example, expediting approval of PEPCO transmission system upgrades and instituting demand response programs.⁹ Indeed, DOE views this order not as a permanent solution to the Central D.C. area's reliability issues, but rather as a bridge between the current untenable situation and a more permanent solution that must be crafted by appropriate parties, including the DCPCS, FERC, environmental regulatory authorities, and relevant private sector parties. This permanent solution may include the installation of the new transmission lines discussed above, the installation of new pollution control equipment at the Mirant Plant, or other means.

As explained above, in the event that one of the two transmission lines that serve the Central D.C. area is out of service (due either to a necessary planned outage or to unforeseen events) and sufficient electricity from the Mirant power plant were not available, then the Central D.C. area would experience an immediate blackout should the one remaining source of electricity fail. This situation must be avoided, and ordering paragraph A of this order ensures that this situation will be avoided. When an outage is planned, Mirant is to be given advance notice and is required to supply necessary generation throughout the period of the outage.¹⁰ In the event of an unexpected outage, Mirant must provide such generation as soon as possible. In the very unlikely eventuality of both transmission lines failing at the same time, Mirant is required to provide sufficient generation to supply the electrical demands of the affected area as soon as possible.

It is essential to determine the level of operation and other steps that will enable Mirant to rapidly respond to an unplanned transmission line outage. Some commenters have urged the Department to order the Plant to run continuously, even if doing so causes ongoing exceedances of the NAAQS. This would assure a high level of reliability of the electricity supply, but of course would not be tailored to particular circumstances in which operation of the Plant would be most necessary to provide needed reliability for the Central D.C. area and might also cause local air quality concerns. Other commenters have urged the Department to do nothing.

⁹ Demand response programs prompt electricity customers to reduce demand, especially during periods of short supply.

¹⁰ In making certain portions of this order effective only upon notice to Mirant by PEPCO of a planned or unplanned outage of one or both of the 230 kV lines, it is similar to the FPA section 202(c) orders issued during the 2000/2001 California energy crisis. In those, DOE ordered certain entities to generate, deliver, interchange and transmit electricity to the California Independent System Operator (California ISO), but the entities were not required to deliver energy or services unless the California ISO had filed with DOE a certificate that it had been unable to acquire adequate supplies of electricity in the market. See Order pursuant to Section 202(c) of the Federal Power Act (December 14, 2000); Order Pursuant to Section 202(c) of the Federal Power Act (January 11, 2001).

The Department is not prepared to order actions that could cause more localized NAAQS exceedances than are necessary in order to assure adequate electric reliability for the Central D.C. area. At the same time, the Department should address the risks that delays in responding to an unplanned transmission line outage would present if measures are available to mitigate that risk. In my judgment, the appropriate balance is struck by (1) requiring Mirant to keep as many units in operation, and take all other measures to reduce the start-up time of units not in operation, for the purpose of providing electrical reliability, as feasible (as further defined in the ordering paragraphs below). Thus, Mirant must take actions to reduce the time it takes to respond to an unplanned outage. This will serve to reduce the risk of a blackout but not at the price of unnecessary exceedances of health-based NAAQS. As Mirant improves its environmental performance, in cooperation with environmental regulators, its ability to react to an unforeseen outage also will improve. Environmental regulators and Mirant can work together, with the Department, to reduce, and perhaps eliminate, any conflict between environmental goals and electric reliability.

This order is effective immediately and will terminate at 12:01 a.m. October 1, 2006. This order may be modified or extended at any time upon order of the Secretary of Energy.

VI. Ordering Paragraphs

For the reasons set forth above, pursuant to section 202(c) of the Federal Power Act, it is hereby ordered that:

A. During any period in which one or both of the 230kV lines serving the Central D.C. area is out of service, whether planned or unplanned, Mirant will operate the Potomac River Generating Plant to produce the amount of power (up to its full capacity) needed to meet demand in the Central D.C. area as specified by PJM for the duration of the outage.

In the event of a planned outage, Potomac River units will generate that amount of electricity specified by PJM to meet demand.

In the event of an unplanned 230 kV line outage, Potomac River units will generate that amount of electricity specified by PJM to meet demand as soon as possible.

When producing electricity pursuant to this paragraph, Mirant shall utilize pollution control equipment and measures to the maximum extent possible to minimize the magnitude and duration of any exceedance of the NAAQS.

B. Mirant shall keep as many units in operation, and shall take all other measures to reduce the start-up time of units not in operation, for the purpose of providing electricity reliability, as “feasible.” For purposes of this paragraph, “feasible” means as determined by the Department of Energy, after consideration of the plan submitted by Mirant pursuant to paragraph D of this order and after consultation with the Environmental Protection Agency, without regard to cost and without causing or significantly contributing to any exceedance of the NAAQS.

C. Notice

In instances of scheduled outages of one of the 230kV lines, PEPCO will give advance notice of the planned outage and the estimated duration of such outage to Mirant, PJM, DOE, FERC, EPA, and DEQ. The notice must be sufficiently in advance of the outage to allow Mirant to bring the required amount of generation needed for reliability purposes on line by the time the outage is scheduled. PEPCO will ensure that only those planned outages needed to maintain or enhance the reliability of the 230 kV lines (or to install new lines) are scheduled and that such outages are scheduled to minimize the environmental effects of the operation of the Plant.

PEPCO will notify DOE, PJM, FERC, EPA, and DEQ of any unplanned outage of one or both of the 230 kV lines as soon as possible, but in no event later than two hours after informing Mirant.

In the event of either a planned or unplanned outage, PJM will specify the amount of electricity that Mirant must provide in order to meet demand.

D. Mirant shall submit a plan to DOE, within 10 days of the date of this order, detailing the steps it will take to ensure compliance with this order. This compliance plan shall include, at minimum, information regarding adequate staffing, materials, and supplies; emissions controls; and length of time necessary to start-up the Plant's generating units in the event of an unplanned or planned outage. DOE will review the compliance plan and order additional requirements if necessary.

E. Pursuant to the terms of FPA section 202(c) and DOE regulations at 10 C.F.R. § 205.376, Mirant and its customers should agree to mutually satisfactory terms for any costs incurred by Mirant under this order. If no agreement can be reached, just and reasonable terms shall be established by a supplemental order.

F. DOE expects that the DCPSC will take all reasonable actions to augment electrical reliability and to reduce electricity demand in the Central D.C. area.

G. DOE will periodically reexamine the need for this order with particular emphasis on: (1) Mirant's progress, working with environmental regulators, in reducing emissions and/or the impact of emissions; and (2) whether the DCPSC is taking all reasonable actions available to it to support electricity reliability in the Central D.C. area.

H. Pursuant to section 313 of the Federal Power Act (16 U.S.C. § 8251), any person, State, municipality, or State commission that is a party to this proceeding and is aggrieved by this order may apply for a rehearing within thirty days. Requests for rehearing may be submitted by mail, facsimile, or electronic mail to the following: (1) mail should be directed to Lawrence Mansueti of the Permitting, Siting, and Analysis Division of the Office of Electricity Delivery and Energy Reliability at the United States Department of Energy, Routing Symbol OE-20, 1000

Independence Avenue, S.W., Washington, D.C. 20585; (2) facsimiles may be submitted to 202-586-5860; (3) e-mail may be submitted to Lawrence.Mansueti@hq.doe.gov.

Issued in Washington, D.C. at _____ this 20th day of December, 2005.

Samuel W. Bodman
Secretary of Energy



Department of Energy

Washington, DC 20585

District of Columbia Public Service Commission

Docket No. EO-05-01

Order No. 202-06-2

On December 20, 2005, in Order No. 202-05-3, I determined that an emergency existed in the Central District of Columbia area due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, a shortage of facilities for the transmission of electric energy and other causes, and that issuance of the order would serve to alleviate the emergency and serve the public interest. Therefore, pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. 824a(c), and section 301(b) of the Department of Energy (DOE) Organization Act, 42 U.S.C. 7151(b), and for the reasons set forth in Order No. 202-05-3, I ordered Mirant Corporation and its wholly owned subsidiary, Mirant Potomac River, LLC, to generate electricity at its Potomac River Generating Station (the Plant) pursuant to the terms of the order.

In Order No. 202-05-3, I noted that the Plant is one of only three sources of electricity that serve the central business district of Washington, D.C., many federal institutions, and the Georgetown area, as well as other portions of Northwest D.C., and the District of Columbia Water and Sewer Authority's Blue Plains Advanced Wastewater Treatment Plant. The order further noted that:

PEPCO has applied to the [District of Columbia Public Service Commission] to construct two new 230 kV lines that would supply electricity to the Central D.C. area. In the same application, PEPCO has proposed building two new 69kV lines to supply the Blue Plains wastewater treatment plant. PEPCO proposes having the two 69 kV lines installed by the summer 2006 peak season, and the two 230 kV lines installed in 18 to 24 months. The two existing 230 kV lines that supply the Central D.C. area would need to be temporarily taken out of service sequentially in order to connect the new lines to the Central D.C. area. Once completed, these lines apparently would provide a high level of electric reliability in the Central D.C. area, even in the absence of production from the Plant.

The two 69 kV lines to the Blue Plains wastewater treatment plant have been completed. The two new 230 kV lines have been approved by the relevant regulatory authorities and are scheduled to be completed and in operation by mid-summer 2007.



On January 18, 2006, DOE issued a notice of the emergency order (published in the Federal Register on January 20, 2006, 71 FR 3279) in which DOE stated that it would prepare a Special Environmental Analysis (SEA) pursuant to the Council on Environmental Quality's Regulations Implementing the Procedural Requirements of the National Environmental Policy Act. The SEA would examine the potential impacts of the operation of the Plant pursuant to Order No. 202-05-3. DOE said it would make the SEA publicly available and would consider information contained in the SEA, and public comments on the SEA, in any future decision making regarding the operation of the Plant. The SEA has not yet been issued, but DOE expects it to be completed shortly.

Because the reliability problems identified in Order No. 202-05-3 continue in the absence of the completion of the two new 230 kV lines, but the SEA has not been completed, I am issuing a short-term extension of the emergency order pending completion and consideration of the SEA and DOE's review of comments thereon.

The Department reiterates its expectation that the DC Public Service Commission pursue demand response initiatives and actively promote conservation as additional means of enhancing reliability in the central D.C. area.

On February 17, 2006, I issued Order No. 202-06-1, which granted certain requests for rehearing of Order No. 202-05-3 for the limited purpose of further consideration. The rehearing requests continue under consideration and no action is being taken on those requests by the issuance of this order.

Based on the above, I find that the circumstances which led to my previous determination that an emergency existed still continue, and therefore I hereby extend Order No. 202-05-3 and all the terms and conditions thereof until 12:01 a.m., December 1, 2006.

Issued in Washington D.C. at 6:00 PM this 28 day of September, 2006.


Samuel W. Bodman
Secretary of Energy

APPENDIX B

EPA's Administrative Compliance Order for the Mirant Potomac River Generation Station

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**UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION III
1650 Arch Street
Philadelphia, Pennsylvania 19103-2029**

In the Matter of:

Mirant Potomac River LLC
Potomac River Generating Station
Alexandria, Virginia

Docket No. CAA-03-2006-0163DA

**ADMINISTRATIVE COMPLIANCE ORDER
BY CONSENT**

I. STATUTORY AUTHORITY

This Order is issued pursuant to Section 113(a)(1) of the Clean Air Act (the "Act"), 42 U.S.C. § 7413(a)(1). Under Section 113(a)(1) of the Act, the Administrator of the United States Environmental Protection Agency ("EPA" or "the Agency") has the authority to issue Orders requiring persons to comply with the requirements of an applicable State Implementation Plan ("SIP") or permit issued by a state. The Administrator has delegated his authority to issue such Orders within the geographical jurisdiction of EPA Region III to the Regional Administrator of EPA Region III, who has re-delegated this authority to the Director of the Air Protection Division of Region III. The geographical jurisdiction of EPA Region III includes the Commonwealth of Virginia.

This Order is issued to Mirant Potomac River, LLC ("Mirant") for its Potomac River Generating Station in Alexandria, Virginia.

II. FINDINGS OF FACT

1. Mirant owns and operates an electricity generating station known as the Potomac River Generating Station ("PRGS") in Alexandria, Virginia.
2. Mirant is a Limited Liability Company organized in the State of Delaware on August 2, 2000.
3. Pursuant to the Order By Consent entered into by Mirant and the Virginia Department of Environmental Quality ("VaDEQ"), effective September 23, 2004, Mirant performed a

Dispersion Modeling Analysis to assess the effect of Downwash (the "downwash study") of emissions from the PRGS. The downwash study used computer modeling to predict ambient concentrations of pollutants emitted by the PRGS under certain weather and atmospheric conditions.

4. Mirant provided the results of the downwash study to VaDEQ in August 2005. By letter dated August 19, 2005, VaDEQ informed Mirant that the downwash study demonstrated that emissions from the PRGS result in, cause or substantially contribute to, modeled violations of the primary National Ambient Air Quality Standards ("NAAQS") for sulfur dioxide ("SO₂"), nitrogen dioxide ("NO₂"), and PM₁₀ under certain atmospheric conditions.
5. VaDEQ's August 19th letter also requested that Mirant immediately undertake "such action as is necessary to ensure protection of human health and the environment, in the area surrounding the Potomac River Generating Station." VaDEQ cited 9 VAC 5-20-180(I) as the authority for this action.
6. The provision of the Virginia State Implementation Plan ("SIP") cited by VaDEQ, 9 VAC 5-20-180(I), has been approved and incorporated into the Virginia SIP at 40 C.F.R. § 52.2420(c), and is therefore federally-enforceable.
7. Mirant shut down all five Units of the PRGS at midnight on August 24, 2005.
8. On August 24, 2005, the District of Columbia Public Service Commission ("DCPSC") filed an "Emergency Petition and Complaint" with the United States Department of Energy ("DOE") and the Federal Energy Regulatory Commission ("FERC"), respectively, pursuant to the Federal Power Act ("FPA"), 16 U.S.C. § 824a(c), 824f and 825h, and Section 301(b) of the DOE Organization Act, 42 U.S.C. § 7151(b). The Emergency Petition requested that DOE find that an emergency exists under Section 202(c) of the FPA and issue an order requiring Mirant to continue operation of the PRGS.
9. Following additional modeling and assessment of the downwash study, Mirant re-started Unit 1 of the PRGS on September 21, 2005. Additional modeling conducted by Mirant indicated that operation of only Unit 1 would not cause any modeled NAAQS exceedances.
10. On December 20th, 2005, the Secretary of Energy issued Order No. 202-05-3 ("DOE Order") finding that an emergency did exist and ordering Mirant to, among other things, submit a plan to DOE detailing the steps to be taken to ensure Mirant's compliance with the DOE Order.
11. On December 30, 2005, Mirant submitted to DOE the Operating Plan setting forth the steps that Mirant would take to ensure compliance with the DOE Order.

12. By letter dated January 4, 2006, DOE required that Mirant "immediately take the necessary steps to implement Option A of the intermediate phase proposed in the [Operating Plan]." The DOE letter also noted that implementation of Option A was an interim measure.
13. In accordance with DOE's directive to maximize electric generation while not causing or contributing to a NAAQS violation, Mirant supplemented the original Operating Plan with additional operating configurations and modeling. The supplements contemplated that Mirant would use trona injection and a blend of low sulfur coal to manage SO₂ emissions. Mirant stated that these supplemental operating scenarios result in no modeled NAAQS exceedances.
14. By letter dated December 22, 2005, EPA issued a Notice to Mirant and the VaDEQ, alleging that Mirant did not immediately undertake the necessary action to protect human health and the environment required by VaDEQ's August 19, 2005 letter, and that Mirant was therefore in violation of 9 VAC 5-20-180(I) and the federally-enforceable Virginia SIP for the period of time in which it failed to immediately shut down all the PRGS Units.
15. Following issuance of the Notice, EPA met with Mirant on several occasions to discuss settlement of EPA's possible enforcement action for the violation alleged in the Notice under Section 113 of the CAA. These discussions, along with discussions with DOE and VaDEQ, have resulted in this Order.
16. In its evaluation of potential PRGS operating scenarios, DOE has determined that the levels of PRGS operation allowed under the terms and conditions of Part IV of this Order are necessary to assure an acceptable level of electric reliability to the District of Columbia under the circumstances.
17. EPA will require use of the AERMOD model with a 24 hour background SO₂ concentration of 51 micrograms per cubic meter ("ug/m³") when evaluating the PRGS's effects on the SO₂ NAAQS. In Mirant's December 30, 2005 Operating Plan and subsequent submissions to DOE and EPA, Mirant has used varying background concentrations for SO₂ in determining the maximum predicted impact of various operating scenarios at the PRGS. EPA has determined that Mirant's use of these varying background concentrations was technically defensible but that additional conservatism will be required in this Order. In an effort to build additional conservatism into Mirant's operating scenarios to ensure protection of the NAAQS, EPA has instructed Mirant to use a background concentration of 51 ug/m³ to add to the AERMOD 24 hour SO₂ modeled pollutant concentrations to determine the maximum predicted impacts for all operational scenarios considered during and incorporated into this Order.
18. EPA has determined through modeling and analysis that there is a strong correlation between the days, hours, and locations of predicted highest 24-hour concentrations of

SO₂ and predicted highest 24-hour concentrations of PM₁₀; that the predicted highest concentrations of SO₂ are higher, relative to the SO₂ NAAQS, than the predicted highest concentrations of PM₁₀ relative to the PM₁₀ NAAQS; and that measures taken to reduce SO₂ emissions from the PRGS facility, such as reduced levels of operation and/or increased levels of trona usage, will also reduce emissions of PM₁₀.

III. CONCLUSIONS OF LAW

19. Mirant is a "person" within the meaning of Section 302(e) of the CAA, 42 U.S.C. § 7602(e), and within the meaning of Section 113(a) of the CAA, 42 U.S.C. § 7413(a), because it is a corporation.
20. EPA concludes that Mirant violated 9 VAC 5-20-180(I) by failing to immediately shut down the boilers at the PRGS upon receipt of the letter from VaDEQ, and that such failure is also a violation of Section 113(a) of the CAA, 42 U.S.C. § 7413(a).
21. Mirant has had an opportunity to confer with the Administrator or his designee regarding this alleged violation and the terms of this Order. Mirant denies that any violation occurred, but agrees to the entry of this Order.
22. EPA has determined that the following schedule and plan for compliance is reasonable, taking into account the seriousness of the modeled NAAQS exceedances and the concerns of DOE regarding electric reliability in the Central D.C. area, and that this schedule is expeditious given the length of time it will take Mirant to take more permanent measures as well as the time it will take for additional electric transmission lines to be put into service to alleviate the emergency as determined by DOE.

IV. ORDER

Based upon the forgoing, under Section 113(a)(4) of the Act, 42 U.S.C. § 7413(a)(4), IT IS DETERMINED AND ORDERED that:

A. Definitions - For the purpose of this Order, the following terms shall have the meanings defined below:

3-Hour Rolling SO₂ and 24-Hour Calendar Day SO₂ Emission Rate.

For the purpose of calculating the specified rate in Table 1 for a specified time period, the actual SO₂ emission rate is determined by dividing the sum of the total pounds of actual SO₂ emissions from the boiler stack of that unit, as determined by hourly CEMS data, as certified by 40 CFR Part 75, by the sum of the total heat input in million Btus from that coal-fired boiler unit.

For any 3 hour rolling period when there are fewer than 2 hours of actual emissions from a coal-fired boiler unit, an emission rate for that 3 hour period that would have to comply with the Table 1 emission rates does not need to be calculated for that unit.

For any calendar day when there are fewer than 3 hours of actual emissions from a coal-fired boiler unit, a 24 hour emission rate to comply with Table 1 need not be calculated for that unit.

On any day when a unit runs between 3 and 18 hours, the complying 24 hour emissions rate for Table 1 shall be calculated as follows:

If a unit operates between 3 hours and 10 hours, the SO₂ limit for that unit equals the 3 hour rate in Table 1 minus 1/3 of the difference between the 3 hr and 24 hr rate for that unit configuration;

If a unit operates 10 hours or more up to 18 hours, the SO₂ limit for that unit equals the 3 hour rate in Table 1 minus 2/3 of the difference between the 3 hr and 24 hr rate for that unit configuration.

If a unit operates 18 hours or more, the 24 hour rate in Table 1 shall apply.

Nothing in this paragraph is intended to allow greater operation of a unit than what is specified in Table 1 where this Order requires operation in accordance with Table 1. In addition, where this Order requires operation in accordance with Table 1 and that configuration calls for unit(s) to operate between 3 and 18 hours, then the Table 1 emission rates shall apply without the above adjustments.

AERMOD Default means Version 04300 of the AERMOD computer model, currently approved for general use by EPA.

AERMOD EBD means the AERMOD computer model with modified direction-specific building dimensions derived from the Wind Tunnel Study.

Alternative Operating Scenario means a method of operating the Potomac River Generating Station during the Model Evaluation Study, which has been approved by EPA and reviewed by VaDEQ.

DOE means the United States Department of Energy

DOE Order means Order No. 202-05-3, issued by the Department of Energy on December 20, 2005 in Docket No. EO-05-01 in response to an Emergency Petition and Complaint filed by the District of Columbia Public Service Commission.

EPA means the United States Environmental Protection Agency, Region III.

Line Outage Situation means that one or both 230 kV transmission lines, serving the Central D.C. area are out of service due to a planned or unplanned outage.

Mirant means Mirant Potomac River, LLC.

Modeled NAAQS Exceedance means a modeled 3-hour average sulfur dioxide concentration which, when a background concentration of 238.4 micrograms per cubic meter is added, exceeds 1,300 micrograms per cubic meter; or a modeled 24-hour average sulfur dioxide concentration which, when a background concentration of 51 micrograms per cubic meter is added, exceeds 365 micrograms per cubic meter; or, a modeled 24 hour PM10 concentration which, when a background concentration of 45 micrograms per cubic meter is added, exceeds 150 micrograms per cubic meter.

Model Evaluation Study or MES means a study proposed by Mirant and approved by EPA and reviewed by VaDEQ to compare multiple computer model predicted ambient air impacts to actual measured ambient air concentrations for the purpose of determining the best performing computer model in evaluating the effects of the emissions resulting from the operation of the PRGS.

Monitoring Plan means a plan proposed by Mirant and approved by EPA and reviewed by VaDEQ as part of the MES for the installation and use of ambient air monitors in the vicinity of the PRGS to monitor ambient air quality impacts of the PRGS.

Monitors means the ambient air monitors installed in accordance with the Monitoring Plan.

NAAQS means the National Ambient Air Quality Standards.

Non-Line Outage Situation means all periods of time that do not qualify as a Line Outage Situation.

Operating Parameters means the hourly average MW load of each unit for each hour of that day at the PRGS, the hourly average SO2 emission rate expressed in lb/MMBtu for each unit for each hour of that day, and the emission rate of PM10 expressed in lb/MMBtu.

Operating Plan means the December 30, 2005 Operating Plan submitted to DOE by Mirant to respond to the requirement for a compliance plan under the DOE Order.

Predictive Modeling means the daily use of an approved AERMOD computer model run in accordance with 40 C.F.R. Part 51, Appendix W, with forecasted weather conditions and planned Operating Parameters for the following day to predict modeled NAAQS compliance on a day-ahead basis.

PJM means the regional transmission organization for the region where the PRGS is located.

PRGS means the coal-fired electric generating station owned by Mirant and located in Alexandria, VA, comprised of three baseload generating units (Units 3, 4, 5) of approximately 102 MW each and two cycling units (Units 1 and 2) of approximately 88 MW each.

VaDEQ means the Virginia Department of Environmental Quality.

Wind Tunnel Study means a study proposed by Mirant using a physical model, as outlined in CPP Wind's Wind Tunnel Model Evaluation protocol, dated January 17, 2006, reviewed by EPA and VaDEQ, and conducted in accordance with EPA Guidance, to evaluate the accuracy of AERMOD Default's assumptions with respect to the direction-specific effective building dimensions when applied to the PRGS.

B. Operation During Non-Line Outage Situations

1. Mirant shall implement and comply with all of the single-unit, two-unit, and three-unit configuration constraints listed in Table 1 below until such time as Mirant is authorized by EPA and DOE to begin an alternative operating scenario as described below. Mirant shall operate each unit within the applicable hours-of-operation and SO₂ emission rate restrictions listed in the table each calendar day. Generally, unit transitions and unit startups will occur within (+/-) four hours of midnight. The following procedures will be followed when there is a transition between operating scenarios:

a. When transitioning between two units, the unit that is coming offline will cease burning coal before the starting unit begins burning coal. Number 2 oil will be burned during the warm-up phase of the starting unit and during the shutdown phase of the unit coming offline. The number of boilers burning coal will not exceed at any time the constraints applicable to the Unit Configurations listed in Table 1.

b. When a change in operating Unit Configuration occurs, Mirant shall, for the balance of the calendar day, meet the more stringent of the 3-hour SO₂ and/or 24-hour SO₂ rate caps and hours of operation applicable to:

- (i.) the Unit Configuration being ceased, and
- (ii.) the Unit Configuration being commenced.

TABLE 1

Unit Configuration	24 Hr Calendar Day SO ₂ Rate - lb/MBtu	3-Hr Rolling SO ₂ Rate - lb/MBtu	Operating Constraints
Unit 1	1.20	1.20	8 hrs max / 8 min / 8 off, 14,800 lb/day
Unit 1	0.84	1.14	None
Unit 2	0.41	0.73	None
Unit 3	0.31	0.66	None
Unit 4	0.36	0.70	None
Unit 5	0.61	0.90	None
Units 1 & 2	0.29	0.50	Both Units: 100% Load 24 hrs/day
Units 1 & 3	0.24	0.51	#1 @ 8 max / 8 min / 8 off, none on #3
Units 2 & 3	0.23	0.40	#2 @ 8 max / 8 min / 8 off, none on #3
Units 1 & 4	0.30	0.54	#1 @ 8 max / 8 min / 8 off, none on #4
Units 2 & 4	0.25	0.44	#2 @ 8 max / 8 min / 8 off, none on #4
Units 1 & 5	0.43	0.60	#1 @ 8 max / 8 min / 8 off, none on #5
Units 2 & 5	0.35	0.55	#2 @ 8 max / 8 min / 8 off, none on #5
Units 3 & 4	0.23	0.43	#3 @ 6 max / 18 min; #4 @ 7 max / 17 min
Units 3 & 5	0.24	0.43	Both units @ 12 hr max / 12 hr min
Units 4 & 5	0.27	0.51	Both units @ 12 hr max / 12 hr min
Units 1, 2 & 3	0.21	0.36	#1&2 @ 5 max / 4 min / 15 off, none on #3
Units 1, 2, & 4	0.24	0.35	#1&2 @ 6 max / 5 min / 13 off, none on #4
Units 1, 2, & 5	0.27	0.42	#1&2 @ 8 max / 8 min / 8 off, none on #5

2. Schedule for Installation of Trona Injection at All Boiler Units

a. In accordance with the schedule set forth in Mirant's Operating Plan of December 30, 2005, Mirant shall ensure that Trona injection units are installed and operated as follows:

(1). March 20, 2006 - In addition to the two portable, rental Trona units, Mirant shall have a third operational Trona injection unit, whether an engineered unit or a rental unit. Mirant shall operate all three Trona units whenever three or more boilers are operating.

(2). April 28, 2006 - Mirant shall have installed and be operating three engineered Trona injection units, and shall operate each unit whenever the boiler to which it is attached is operating. Mirant shall operate the rental Trona units on boilers not equipped with operating engineered units.

(3). May 31, 2006 - Mirant shall have installed and be operating

all five engineered Trona injection units, and shall operate each unit whenever the boiler to which it is attached is operating.

3. Model Evaluation Study

a. Mirant shall undertake a Model Evaluation Study to determine the best performing model for predicting the computer-modeled ambient air quality impacts from the PRGS's operations. Prior to beginning the MES, Mirant must submit to EPA for approval an MES protocol, and simultaneously send a copy to VaDEQ. Mirant may begin operating the PRGS in a manner that does not cause or contribute to Modeled NAAQS Exceedances by using Predictive Modeling as described in subsection 4 below, after completing the following tasks:

- (1). EPA approval of the MES protocol;
- (2). installation and operation of at least 3 SO₂ monitors in accordance with the approved monitoring plan;
- (3). execution of this Order by EPA; and
- (4). authorization by DOE for Mirant to operate in accordance with this Order.

b. Upon commencement of daily predictive modeling performed in conjunction with the MES, the SO₂ emission rate limitations and other unit operating restrictions set forth in Table 1 shall no longer apply unless otherwise indicated. The Table 1 restrictions apply if Mirant ceases to operate the PRGS in accordance with the MES.

4. Operations in Accordance with Daily Predictive Modeling

a. By 10 AM each morning, Mirant shall collect actual weather predictions from the National Weather Service for the Reagan National Airport and use them along with planned Operating Parameters as inputs to conduct a computer modeling run for the following day using AERMOD Default. If the modeling confirms that Mirant's planned operations for the following day will not cause or contribute to a Modeled NAAQS Exceedance, Mirant may operate on the day modeled in accordance with the modeled Operating Parameters. If the Predictive Modeling indicates that the planned Operating Parameters will result in one or more Modeled NAAQS Exceedances, Mirant shall not run under those operating parameters but shall continue to adjust its planned operations and conduct additional modeling runs using the adjusted Operating Parameters to confirm that the adjusted operations will not cause or contribute to a Modeled NAAQS Exceedance for the day modeled.

b. During Line Outage Situations, Predictive Modeling must continue to be performed but the PRGS shall be operated under the Line Outage Situation provision in accordance with the DOE Order and this Order.

c. If the Predictive Modeling indicates that the predicted weather conditions and planned Operating Parameters do not result in a Modeled NAAQS Exceedance,

Mirant is authorized to operate using the planned Operating Parameters and shall not be in violation of this Order; or 9 VAC 5-20-180(I), as incorporated into the Virginia SIP at 40 C.F.R. 52.2420(c); nor shall such operation be deemed to give a right for a cause of action for any alleged violation of the NAAQS as a result of Mirant causing or contributing to any modeled or monitored exceedance of the NAAQS. This release shall only apply to alleged exceedances or violations occurring during the lifetime of the Order or the duration of the MES if the requirements of this Order have been incorporated into a state operating permit; shall only apply to laws in existence on the effective date of the Order; and shall not prevent Virginia from issuing an order under 9 VAC 5-20-180(I) or EPA from taking action under Section 303 of the Clean Air Act.

5. Operation During Certain Periods of Elevated SO₂ Impacts After MES

Approval

a. As a precaution, after the installation of at least three monitors, Mirant shall institute additional measures that will apply whenever ambient concentrations of SO₂ are elevated, as defined below. Specifically, Mirant shall:

(1). Install a monitor alert system in the Potomac River Control Room that registers an audible alarm if in any one hour the average measured ambient concentration of SO₂ at any monitor is equal to or greater than 80% of the 3 hour SO₂ National Ambient Air Quality Standard, measured as 400 parts per billion (1,040 $\mu\text{g}/\text{m}^3$).

(a). During the hour following the sounding of the alarm, Mirant shall make operational adjustments, which may include increasing Trona injection and/or decreasing operation and shall observe the effect of these adjustments on the average, measured ambient concentration of SO₂.

(b). If, at the end of the second hour, the average measured ambient concentration of SO₂ is not equal to or less than 1,040 $\mu\text{g}/\text{m}^3$, Mirant shall adjust its operations to conform to the scenarios described in Table 1 until the rolling 3 hour average is less than 1,040 $\mu\text{g}/\text{m}^3$.

(2). Mirant shall also configure the audible alarm to sound if, in any 12 hour period, any monitor measures an average, ambient concentration of SO₂ equal to or greater than 80% of the 24 hour SO₂ National Ambient Air Quality Standard, measured as 112 parts per billion (292 $\mu\text{g}/\text{m}^3$).

(a). During the following 6 hours, Mirant shall make operational adjustments, which may include increasing Trona injection and/or decreasing operation and shall observe the effect of these adjustments on the measured ambient concentration of SO₂.

(b). If, at the end of the 6 hour period, the average, measured ambient concentration of SO₂ is not equal to or less than 292 $\mu\text{g}/\text{m}^3$, Mirant shall adjust its operations to conform to the scenarios described in Table 1 for the balance of the calendar day.

(3). Mirant shall also configure the audible alarm to sound if, after the first 6 months of operation, any monitor measures an average, ambient concentration of SO₂ equal to or greater than 80% of the annual average NAAQS, measured as 64 µg/m³.

(a). During the following 3 months, Mirant shall monitor the 7 month, 8 month and 9 month averages.

(b). If, at the end of 9 months, the average, measured ambient concentration of SO₂ is not equal to or less than 64 µg/m³, Mirant shall adjust its operations so that the annual, measured ambient concentration of SO₂ does not exceed 80 µg/m³.

(4). If the audible alarm sounds more than 5 times in a calendar month, Mirant shall, on a one-time basis, adjust the alarm to 75% of the applicable NAAQS.

6. PM10 Predictive Modeling

Whenever Mirant operates 4 or more units, it shall abide by an emission rate of 0.055 lbs/MM Btu and shall first conduct Predictive Modeling using this rate to determine whether operation of the units causes or contributes to a Modeled NAAQS Exceedance. If the Predictive Modeling indicates that the planned Operating Parameters will result in a Modeled NAAQS Exceedance for PM10, Mirant shall adjust its planned operating scenario and re-run the Predictive Modeling with an emission rate of 0.055 lbs/MM Btu until such time as Mirant confirms through Predictive Modeling that the adjusted operations will not cause or contribute to a Modeled NAAQS Exceedance for PM10.

7. AERMOD EBD - Physical Changes Requiring Model Changes

If Mirant elects to refine the AERMOD Default model by performing a Wind Tunnel Study, Mirant will submit a Wind Tunnel Study evaluation protocol for review by EPA and VaDEQ and approval by EPA. The protocol will describe the technical features of the proposed Wind Tunnel Study and the theoretical basis for demonstrating that the data generated should be used to develop a site-specific set of assumptions, including equivalent building dimensions, to be applied to AERMOD Default.

The results of the Wind Tunnel Study shall be submitted to EPA for approval and may result in site-specific equivalent building dimensions to be used in lieu of the assumptions in the AERMOD Default model. The results must be submitted to EPA no later than 90 days following entry of this AO. Upon approval of AERMOD EBD by EPA and VaDEQ, Mirant shall operate for the balance of the MES study period applying AERMOD EBD in its Predictive Modeling.

As the Model Evaluation Study progresses, Mirant may make other changes at the PRGS, including physical changes such as changes to the stacks. In that event, inputs utilized during the Predictive Modeling and in the models evaluated at the conclusion of the Model Evaluation Study (and the model used to develop emission limits for the PRGS) may, after EPA

approval, be adjusted to correspond to these changes. However, the MES study period must be conducted for a minimum of six months following any physical change in order to obtain monitoring data upon which to evaluate the models.

8. Monitoring and Comparison Modeling During the Model Evaluation

Study

In accordance with the MES Protocol, as attached, Mirant shall install and operate a total of six (6) ambient SO₂ monitors in the preferred locations or alternate locations as described below:

a. Preferred locations

(1). Two monitors on the roof of Marina Towers, with one located on the Southeast wing and one at the center of the building;

(2). One monitor east of the PRGS, approximately due east of Stack 5 on the west bank of the Potomac River;

(3). One monitor southeast of the PRGS, along the facility fenceline, near the River;

(4). One monitor approximately 800 meters north of Marina Towers; and

(5). One monitor on the roof of a building in the Harbor Terrace complex three

EPA will work with Mirant to assist in obtaining permission needed to install monitors in these preferred locations.

b. Alternate Locations: If EPA determines that notwithstanding Mirant's good faith and reasonable efforts to obtain permission to install monitors in the preferred locations, it is impractical to install some or all of the monitors in the preferred locations in a timely manner because the owner of the preferred monitor location declines to host the SO₂ monitor(s) or the preferred location is unavailable or impractical for any other reason, EPA will authorize installation of monitors at some or all of the five alternative SO₂ monitor locations set forth in the MES Protocol, as summarized below:

(1) Southwest of the PRGS on the rooftop of Braddock Place;

(2) Approximately 600 meters South-Southeast of the stack locations, at ground level along the Potomac River;

(3) Approximately 300 meters Southwest of the PRGS at ground level;

(4) Approximately 600 meters South-Southwest of the PRGS at ground level; and

(5) Approximately 100 meters SW of the plant at ground level.

c. Deadline for ambient monitor installation: Mirant shall have all six monitors installed and operating within 60 days of the execution of this Order. EPA may, at its own discretion, extend the deadline, and/or change locations, for installation and/or operation of one or all of the monitors and in the event that EPA determines that one of the preferred locations is impractical and authorizes use of an alternate location, Mirant shall have an additional 30 days in which to install that monitor.

d. Operation, Maintenance, and Quality Assurance/Quality Control ("QA/QC") of monitors - It shall be the responsibility of Mirant to ensure that the monitors are operated, maintained, and subject to the appropriate QA/QC provisions set forth at Appendix A to 40 C.F.R. Part 58.

e. Follow-up modeling: The data generated by the monitors shall be used at the end of the study to conduct a model evaluation. Until such time as all the ambient air monitors are installed in accordance with the Monitoring Plan and begin measuring and recording ambient air data, Mirant shall perform "follow up" computer modeling using actual weather conditions and Operating Parameters, and shall report the results to EPA and VaDEQ on a monthly basis, as described below. This "follow-up" modeling will be performed on the Monday following the previous week of operation.

9. Determination of Best Performing Model at Conclusion of Model Evaluation Study

At the conclusion of the MES, the performance of the applicable models will be evaluated in accordance with the document "Protocol for Determining the Best Performing Model." EPA-454/R-92-025, Sept. 1992, Comparing Computer Model-Predicted Air Concentrations to Actual Ambient Air Concentrations Measured by the Monitors. The information yielded by the comparison of model predictions to measured ambient concentrations will result in a determination by EPA and VaDEQ as to which model is best-performing. Thereafter, the best-performing model shall be used to conduct computer modeling to develop permanent emission limits at the PRGS.

10. Reporting

a. Throughout the period of the MES, Mirant shall deliver to EPA and VaDEQ monthly: (1) the modeled input files and results of the daily Predictive Modeling for the preceding month, including the hourly average heat input in MMBtu for each unit and the exit velocity (or exhaust volume) for each unit; (2) verification that the planned Operating Parameters utilized for Predictive Modeling in the preceding month were not exceeded, or if exceeded, documentation describing that exceedance; (3) the inputs and results of "follow-up" modeling for the preceding month (or portion thereof during which all Monitors were not in place), including the hourly average heat input in MMBtu for each unit and the exit velocity (or

exhaust volume) for each unit, but only until commencement of operation of all Monitors, and;
(4) after installation of the Monitors, the data generated by the Monitors.

b. If at any time the "follow-up" modeling demonstrates a modeled exceedance of the NAAQS or the Monitors demonstrate an actual exceedance of the NAAQS, Mirant shall report such modeled or monitored exceedance to EPA and VaDEQ within 3 days of the modeled or monitored exceedance for a determination as to whether corrective action is required.

C. Operation During Line Outage Situations

1. During a Line Outage Situation, Mirant shall operate the PRGS to produce the amount of power needed to meet the load demand in the Central D.C. area, as specified by PJM and in accordance with the DOE Order. During such operations, Mirant shall take all reasonable steps to limit the emissions of PM10, NOX and SO2 from each boiler, including operating only the number of units necessary to meet PJM's directive and optimizing its use of Trona injection to minimize SO2 emissions. During a Line Outage Situation, Mirant shall achieve 80% reduction of SO2 emissions unless: 1) Mirant demonstrates, through predictive modeling or otherwise, that 80% reduction is not necessary to achieve compliance with the NAAQS; or 2) Mirant demonstrates that 80% reduction is not logistically feasible because of factors such as the quantity of available Trona and predicted duration of the outage. In the event that Mirant demonstrates that 80% reduction is not logistically feasible, it shall submit a plan to EPA for optimizing its use of Trona injection so as to maximize SO2 reduction and the plan shall propose control measures and removal efficiencies to be achieved during the Line Outage Situation. If Mirant has 30 days notice in advance of the Line Outage Situation, it shall submit the plan to EPA for approval 15 days before commencement of the Line Outage. If Mirant has less than 30 days advance notice of the Line Outage Situation, Mirant shall submit the plan to EPA for approval as promptly as reasonably possible under the circumstances. It is understood and acknowledged that the plan to be followed for an unscheduled Line Outage Situation will depend upon the specific circumstances at the time of the unscheduled Line Outage Situation. Nothing here shall diminish Mirant's obligation to produce the amount of power needed to meet the load demand in the Central D.C. area, as specified by PJM, and in accordance with DOE's Order.

2. Malfunctions of emission control devices, such as Trona injection, shall not be deemed a failure to limit the emissions during a line outage, provided that Mirant has made reasonable efforts to avoid the malfunction and to promptly correct the malfunction. All emissions during a Line Outage Situation count toward any other permit, statutory, or regulatory limits for the PRGS. Upon Mirant's request, EPA (after consultation with DOE) will provide contemporaneous written confirmation of the existence of a Line Outage Situation. If Mirant operates the PRGS in accordance with dispatch directions from PJM and the relevant terms of this Order during a Line Outage Situation, Mirant shall not be in violation of this Order; or 9 VAC 5-20-180(I), as incorporated into the Virginia SIP at 40 C.F.R. 52.2420(c); nor shall such operation be deemed to give a right for a cause of action for any alleged violation of the

NAAQS as a result of Mirant causing or contributing to any modeled or monitored exceedance of the NAAQS. This release shall only apply to alleged exceedances or violations occurring during the lifetime of the Order or the duration of the MES if the requirements of this Order have been incorporated into a state operating permit; shall only apply to laws in existence on the effective date of the Order; and shall not prevent Virginia from issuing an order under 9 VAC 5-20-180(1) or EPA from taking action under Section 303 of the Clean Air Act.

D. General Provisions

1. At all times, Mirant shall not emit more than 3700 tons of NO_x per year and shall limit the emission rate of PM₁₀ to 0.055 lbs/MMBtu.
2. Mirant's actions shall be consistent with all provisions of federal and state law, including but not limited to, the Clean Air Act, all federal regulations promulgated under the Clean Air Act, and any other applicable laws, including the Virginia State Implementation Plan.

E. Permitting Requirements

Within the 12 month period following entry of this Order, Mirant must cooperate with VaDEQ in the development of operating permit emission limits protective of all NAAQS. Mirant agrees that the obligations of this Order, to the extent they have not been completed, may become obligations in the operating permit issued by VaDEQ. Mirant further agrees that during the implementation of this Order, it will prepare and submit to EPA and VaDEQ an analysis of the applicability of NSR/PSD to the PRGS due to the installation of Trona injection and any additional fugitive emissions resulting from that installation.

V. PARTIES BOUND

This Order shall apply to and be binding upon Mirant, its agents, successors, and assigns and upon all persons, contractors and consultants acting under or for Mirant, or persons acting in concert with Mirant who have actual knowledge of this Order or any combination thereof with respect to matters addressed in this Order. No change in ownership or corporate or partnership status will in any way alter Mirant's responsibilities under this Order.

In the event of any change in ownership or control of the PRGS, Mirant shall notify the EPA in writing at least thirty (30) days in advance of such change and shall provide a copy of this Order to the transferee-in-interest of the PRGS, prior to any agreement for transfer.

VI. RESPONSES TO ORDER

Information required to be submitted to EPA under this Order must be sent to:

Chief, Air Enforcement Branch
Air Protection Division,

U.S. Environmental Protection Agency, Region 3
1650 Arch St.
Philadelphia, PA 19103

And

Douglas J. Snyder
Assistant Regional Counsel
Office of Regional Counsel (3RC10)
U.S. Environmental Protection Agency, Region 3
1650 Arch St.
Philadelphia, PA 19103

VII. EFFECT OF COMPLIANCE ORDER

As set forth in Section 113(a)(4) of the Act, 42 U.S.C. § 7413(a)(4), nothing in this Administrative Compliance Order by Consent shall prevent EPA from assessing any penalties, or otherwise affect or limit the United States' authority to enforce other provisions of the Act, or affect any person's obligations to comply with any Section of the Act or with any term or condition of any permit or applicable implementation plan promulgated or approved under the Act. Further, nothing in this Order shall limit or otherwise preclude the United States from taking criminal or additional civil judicial or administrative enforcement action against Mirant or any third parties with regard to the PRGS pursuant to any other federal or state law, regulation or permit condition, or for Mirant's failure to comply with any requirements of this Order. Nothing herein shall be construed to limit the authority of the EPA to undertake action against any person, including Mirant, in response to any condition that EPA determines may present an imminent and substantial endangerment to the public health, public welfare or the environment. EPA reserves any rights and remedies available to it to enforce the provisions of this Order, the Act and its implementing provisions, and of any other federal laws or regulations for which it has jurisdiction following the entry of this Order.

For the purposes of this proceeding only, Mirant hereby expressly waives its right to any appeal of this Order which it may have under Section 307(b) of the CAA, 42 U.S.C. § 7607(b), and waives the right to challenge the terms of this Order in any action taken to enforce this Order pursuant to Section 113(b) of the CAA, 42 U.S.C. § 7413(b).

VIII. ENFORCEMENT

Failure to comply with this Order may result in a judicial or administrative action for appropriate relief, including civil penalties, as provided in Section 113 of the Act, 42 U.S.C. § 7413. EPA retains full authority to enforce the requirements of the Clean Air Act, 42 U.S.C. §§ 7401-7642, and nothing in this Order shall be construed to limit that authority except as otherwise provided herein.

IX. CERTIFICATION OF REPORTS

Any notice, report, certification, data presentation, or other document submitted by Mirant under or pursuant to this Order, which discusses, describes, demonstrates, or supports any finding or makes any representation concerning Mirant's compliance or non-compliance with any requirement(s) of this Order, shall be certified by a responsible corporate official of Mirant. The term "responsible corporate official" means (a) the Chairman or Chief Operating Officer of Mirant, or (b) Vice President of Operations for PRGS.

23. The certification required by the preceding paragraph of this Order shall be in the following form:

Except as provided below, I certify that the information contained in or accompanying this (type of submission) is true, accurate, and complete. As to (the/those) portion(s) of this (type of submission) for which I cannot personally verify (its/their) accuracy, I certify under the penalty of law that this (type of submission) and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

Signature: _____
Name(print): _____

X. EFFECTIVE DATE AND OPPORTUNITY FOR CONFERENCE

24. By signing this Order, Mirant agrees that it has had an opportunity to confer on the terms of this Order with EPA and thereby waives its opportunity pursuant to Section 113(a)(4) to confer further with EPA concerning the violation(s) alleged in the above Order before the Order takes effect. Therefore, this Order shall be effective upon Mirant's receipt of a copy of the Order signed by the Director of the Air Protection Division, Region 3, or her designee. This Order shall expire one year after execution of the Order, in accordance with Section 113(a)(4) of the CAA, unless it is terminated sooner by EPA.

XI. FAILURE TO PERFORM

25. In the event of an inability or anticipated inability on the part of Mirant to perform any of the actions or work required by this Order in the time and manner required herein, Mirant shall notify EPA orally within twenty-four (24) hours of such event (or, if the event occurs on a Friday

or Saturday, Sunday, or legal holiday, no later than the following business day) and in writing as soon as possible, but in no event more than three (3) days after such event. Such notice shall set forth the reason(s) for, and the expected duration of, the inability to perform; the actions taken and to be taken by Mirant to avoid and mitigate the impact of such inability to perform; and the proposed schedule for completing such actions. Such notification shall not relieve Mirant of any obligation of this Order. Mirant shall take all reasonable actions to prevent and minimize any delay.

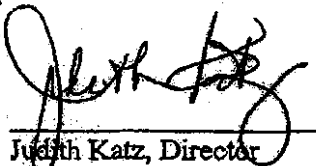
XII. BUSINESS CONFIDENTIALITY

26. Mirant is entitled to assert a claim of business confidentiality covering all or part of any requested information, in the manner described in 40 C.F.R. § 2.203(b), unless such information is "emission data" as defined in 40 C.F.R. § 2.301(a)(2). Information subject to a claim of business confidentiality will be made available to the public only in accordance with the procedures set forth in 40 C.F.R. Part 2, Subpart B. Unless a confidentiality claim is asserted at the time requested information is provided, EPA may make this information available to the public without further notice to you.

XIII. COPIES OF ADMINISTRATIVE COMPLIANCE ORDER BY CONSENT

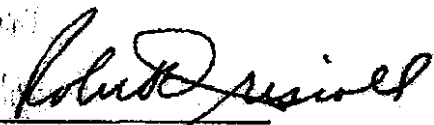
A copy of this Order will be sent to James Sydnor, Virginia Department of Environmental Quality.

Dated: June 1, 2006


Judith Katz, Director
Air Protection Division
U.S. Environmental Protection Agency
Region III

The undersigned represents that he or she is a duly authorized representative of Mirant Potomac River, LLC for the purpose of signing this Order, and that Mirant agrees to the terms of this Order.

Dated: June 1, 2006


Robert Driscoll
Chief Operating Officer

APPENDIX C

***Federal Register* Notice of Emergency Action and
Correspondence with the Council on Environmental Quality**

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ACTION: Notice of public meeting agenda.

DATE AND TIME: Thursday, February 2, 2006, 10 a.m.–1 p.m.

PLACE: Hyatt Regency (Valley Forge Room), 400 New Jersey Avenue, NW., Washington, DC 20001. (Metro Stop: Union Station).

AGENDA: The Commission will receive the following reports: Title II Requirements Payments Update; and updates on other administrative matters. The Commission will receive presentations on the following topics: Implementation of the EAC Voting System Certification Program.

This meeting will be open to the public.

FOR FURTHER INFORMATION CONTACT: Bryan Whitener. Telephone: (202) 566–3100.

Ray Martinez III,

Vice-Chairman, U.S. Election Assistance Commission.

[FR Doc. 06–607 Filed 1–18–06; 3:32 pm]

BILLING CODE 6820–KF–M

DEPARTMENT OF ENERGY

Emergency Order To Resume Limited Operation at the Potomac River Generating Station, Alexandria, VA, in Response to Electricity Reliability Concerns in Washington, DC

AGENCY: Department of Energy.

ACTION: Notice of emergency action.

SUMMARY: Pursuant to 10 CFR 1021.343, the U.S. Department of Energy is issuing this Notice to document emergency actions that it has taken, and to set forth the steps it intends to take in the future, to comply with the National Environmental Policy Act (NEPA) in the matter described in this Notice.

On August 24, 2005, Mirant Corporation, and its wholly owned subsidiary, Mirant Potomac River, LLC (collectively referred to herein as Mirant), ceased operations at its Potomac River Generating Station (the “Plant”) in Alexandria, Virginia, after modeling that it conducted indicated that the Plant’s operations were causing exceedances of the National Ambient Air Quality Standards (NAAQS) of the Clean Air Act. On the same day, the District of Columbia Public Service Commission (DCPSC) filed with the U.S. Department of Energy (DOE or “Department”), a petition for an emergency order pursuant to section 202(c) of the Federal Power Act (FPA), asserting that the Plant’s closure reduced the reliability of the electrical

supply to much of the central business district of the District of Columbia, many federal institutions, the Georgetown area in DC, as well as other portions of Northwest DC, and the District of Columbia Water and Sewer Authority’s Blue Plains Advanced Water Treatment Plant (collectively referred to herein as the “Central DC area”), placing these electrical customers in risk of a blackout.

After an exhaustive review of the facts, and consultation with Federal and state officials responsible for environmental compliance and the private entities responsible for electricity transmission, the Secretary of the Department of Energy on December 20, 2005, issued an emergency order (the “Order”) directing the Plant’s owner, Mirant, to generate electricity at the coal-fired Plant under certain, limited circumstances. The section below on “Further Information” includes information on how to obtain paper and electronic copies of the Order.

In emergency situations such as this one, the Council on Environmental Quality (CEQ) Regulations Implementing the Procedural Requirements of NEPA at 40 CFR 1506.11 provide that a federal agency may take an action with significant environmental impacts without observing the provisions of the NEPA regulations associated with preparing an Environmental Impact Statement (EIS). Instead, the agency should consult with CEQ to determine what alternative arrangements the agency will take in lieu of preparing a normal NEPA EIS. DOE has consulted with CEQ about alternative arrangements it will take in this matter and is publishing this notice to inform the public of those arrangements pursuant to DOE’s NEPA regulations at 10 CFR 1021.343.

Consistent with its consultation with CEQ, DOE will implement the following alternative arrangements: (1) Prepare a Special Environmental Analysis (SEA) that will examine the potential impacts from issuance of the order, and identify potential mitigation measures; (2) provide opportunities for public involvement by disseminating information related to the environmental effects of Mirant’s operations and by accepting public comment on this notice, the compliance plan Mirant submitted to DOE, and the SEA; (3) continue consultations with appropriate agencies with regard to relevant environmental issues; and (4) identify in the SEA any steps that DOE believes can be taken to mitigate the impacts from its Order.

DATES: Comments on this notice and on issues to be addressed in the SEA should be submitted to DOE on or before February 21, 2006.

ADDRESSES: Comments should be addressed to: Lawrence Mansueti, Permitting, Siting, and Analysis Division, Office of Electricity Delivery and Energy Reliability (OE–20), U.S. Department of Energy, 1000 Independence Avenue, SW., Washington, DC 20585–0119; telephone: 202–586–2588; fax: 202–586–5860; Lawrence.Mansueti@hq.doe.gov.

FOR FURTHER INFORMATION CONTACT: For further information on this Notice, to obtain paper copies of the Order and compliance plan, to submit comments on the compliance plan, or for information on the emergency activities related to the Plant, contact Mr. Mansueti at the above address. In addition, all publicly available documents, including the Order and compliance plan, are available on DOE’s Web site for this matter at http://www.electricity.doe.gov/about/dcpsc_docket.cfm or via hyperlinks from that Web site (referred to herein as the “Mirant matter Web site”). Copies of the SEA will also be available on the DOE NEPA Web site at <http://www.eh.doe.gov/nepa/>.

For information on the DOE NEPA process, please contact: Carol M. Borgstrom, Director, Office of NEPA Policy and Compliance (EH–42), U.S. Department of Energy, 1000 Independence Avenue, SW., Washington, DC 20585–0119; telephone: 202–586–4600; fax: 202–586–7031; or leave a toll-free message at: 1–800–472–2756.

SUPPLEMENTARY INFORMATION:

Procedural Background

On August 19, 2005, Mirant submitted to the Virginia Department of Environmental Quality (DEQ) a computerized emissions modeling study Mirant had conducted of its Plant that indicated that emissions from the Plant caused or contributed to significant localized exceedances of the NAAQS. Also on August 19, 2005, DEQ issued a letter to Mirant which requested “that Mirant *immediately* undertake such action as is necessary to ensure protection of human health and the environment, in the area surrounding the Potomac River Generating Station, including the potential reduction of levels of operation, or potential shut down of the facility.” (emphasis in original). On August 24, 2005, Mirant shut down all five of the generating units at the Plant, and on the same day, the District of Columbia Public Service

Commission (DCPSC) filed an Emergency Petition and Complaint with DOE and the Federal Energy Regulatory Commission (FERC) pursuant to the Federal Power Act (FPA). The DCPSC requested the Secretary of Energy to find that an emergency existed under section 202(c) of the FPA and to issue an order directing Mirant to continue operation of the Plant. The basis for the petition was that the shutdown of the Plant “* * * will have a drastic and potentially immediate effect on the electric reliability in the greater Washington, DC, area and could expose hundreds of thousands of consumers, agencies of the Federal Government and critical federal infrastructure to curtailments of electric service, load shedding and, potentially, blackouts.” On September 20, 2005, Mirant restarted its unit number one on an 8/8/8 basis—that is, in any given 24-hour period, the unit runs for eight hours at its maximum level of 88 MW, eight hours at its minimum level of 35 MW, and has eight hours when it does not run. DOE has been informed that both the U.S. Environmental Protection Agency (EPA) and DEQ acknowledge that the operation of this unit in this manner does not result in any modeled NAAQS exceedances.

Electricity Reliability

The coal-fired Mirant Plant consists of five generating units, two of which are cycling units that range in output from 35 MW to 88 MW, and three of which are baseload units that range in output from 35 MW to 102 MW. The Plant is one of only three sources of electricity to the Central DC area. The other two sources are two 230,000-volt (230 kV) transmission lines that deliver electricity from other generating sources in the regional electric grid operated by PJM Interconnection (PJM). Although there are other generating units in close physical proximity to the Central DC area, there are no transmission lines that would allow delivery of power from these other units to reach the Central DC area. Under North American Electric Reliability Council (NERC) standards, at a minimum, the power system must carry at least enough contingency reserves of electricity to cover the most severe single contingency. The standards require that an area's system always be operated with sufficient reserves to compensate for the sudden failure of the area's most important single generator or transmission line. Based on the fact that the Central DC area has only three sources of supply, the Plant and the two 230 kV transmission lines, in order to maintain a minimally reliable electric power

system, the Plant must be available to run when one of the 230 kV lines is out of service, because if the remaining line failed there would be no other source of electricity to serve the Central DC area load.

The outage of one of these two lines is not merely a theoretical possibility. Since 2000, there have been 34 one-line outages for maintenance, and seven occasions where one of the lines has failed unexpectedly. DOE has been informed that, prior to 2000, there were two occasions when both of the lines failed simultaneously. Moreover, just days before issuance of the Order, PJM informed DOE on December 16, 2005, that on the previous night, “one of the two circuits critical to providing service to the District tripped. Continued [electric] service to certain load within the District was at that time entirely dependent on the remaining circuit.” Fortunately, full service to the line that failed was restored by the morning of December 16, 2005. Nonetheless, there can be no assurance that the Central DC area would be so lucky next time. In addition, the Potomac Electric Power Company (PEPCO) informed DOE that it needed to perform maintenance on the lines in January of 2006.

The Order

On December 20, 2005, DOE found that in the circumstances presented, an emergency existed within the meaning of section 202(c) of the FPA because of the reasonable possibility an outage would occur that would cause a blackout, the number and importance of facilities and operations in our Nation's Capital that would be potentially affected by such a blackout, the extended number of hours of any blackout that might in fact occur, and the fact that the current situation violated applicable reliability standards. PEPCO has applied to the DCPSC to construct two additional 230 kV lines that would supply electricity to the Central DC area and in the same application, proposed building two new 69kV lines to supply the Blue Plains wastewater treatment plant. Once completed, these lines will likely provide a high level of electricity reliability in the Central DC area, even in the absence of production from the Plant. However, it will likely take 18–24 months to construct the new lines.

Based on this finding, on December 20, 2005, DOE issued an Order requiring Mirant to, among other things, (1) operate the Plant to produce the amount of power (up to its full capabilities) needed to meet demand in the Central DC area during any period in which one or both of the 230kV lines serving the

Central DC area is out of service as specified by PJM for the duration of the outage, and (2) keep as many generating units in operation and take all other measures to reduce the start-up time of units not in operation, for the purpose of providing electricity reliability, as feasible, as determined by DOE after consideration of the plan submitted by Mirant pursuant to the Order and after consultation with EPA, without regard to cost, and without causing or significantly contributing to any exceedance of the NAAQS. A blackout in the Central DC area would have drastic impacts on the environment, as well as for the employees and citizens of the Central DC area, affecting hundreds of thousands of residents and workers, as well as public safety and protection facilities, including hospitals, police, and fire facilities. In addition, DOE has been informed that within 24 hours of a blackout in the Central DC area, untreated sewage from the Blue Plains Wastewater Treatment plant would be discharged into the Potomac River.

The time period for DOE's Order extends through October 1, 2006.

Mirant's Compliance Plan

Pursuant to DOE's Order, Mirant submitted a compliance plan (referred to as the Operating Plan by Mirant) on December 30, 2005. The plan outlines a proposed temporary phase, and two options for a proposed intermediate phase, Option A and Option B. All proposals include the use of “trona” (sodium sesquicarbonate, a naturally occurring substance similar to baking soda) and/or lower sulfur coal to manage air emissions. On January 4, 2006, DOE authorized Mirant to “immediately take the necessary steps to implement Option A of the intermediate phase proposed in the implementation plan,” stating that “Mirant represents that implementation of this option will produce no NAAQS exceedances.” DOE will work with EPA to verify the accuracy of that representation. DOE is still in the process of reviewing the other proposals described in Mirant's compliance plan in consultation with EPA.

NEPA Compliance Actions

Pursuant to CEQ regulations at 40 CFR 1506.11, DOE consulted with CEQ on December 20, 2005, December 22, 2005, January 13, 2006, and January 17, 2006, about formulating a plan for alternative arrangements. Under the agreed upon alternative arrangements plan, which will expire October 1, 2006, unless extended, DOE will:

1. *Prepare a Special Environmental Analysis (SEA).* The SEA will examine potential impacts resulting from issuance of the Order, and describe further DOE decisionmaking regarding reasonable future alternatives and potential further mitigation actions DOE may take in this matter. The analysis will present reasonably foreseeable impacts from possible changes in operations of the Plant over the time until two additional transmission lines planned by PEPCO are installed. DOE intends to issue its SEA no later than August 2006 and will make it available to the public on the DOE NEPA and Mirant matter Web sites as well as announce its availability in the **Federal Register**. DOE will consider information contained in the SEA, and public input received on the SEA, in any future decisionmaking in this matter.

2. *Provide Opportunities for Public Involvement.* DOE is currently accepting public comments on the compliance plan that DOE required Mirant to submit under the DOE Order. DOE also invites public comments on this Notice, as well as on issues to be addressed in the SEA. DOE will consider public input in determining appropriate mitigation measures and any additional actions DOE may take as DOE adaptively manages implementation of the Order. DOE will post on the Mirant matter Web site publicly available information (not exempt from disclosure under the Freedom of Information Act) regarding the environmental effects of ongoing or alternative operations of the Plant (e.g., reasonably available ambient air quality data and results of air quality modeling), that the Department receives from Mirant, EPA, and DEQ.

3. *Continue Agency Consultations.* DOE will continue to consult with EPA and DEQ concerning information on emissions, modeling results, potential mitigation measures, and any changes to the operation of the Plant. EPA will act as a "cooperating agency" (see 40 CFR 1501.6 and 1508.5) for purposes of providing reasonably available public information regarding the environmental effects of operations of the Plant to be disseminated via DOE's Mirant matter Web site and evaluated in the SEA.

4. *Identify Mitigation.* DOE will identify in its SEA any steps that it believes can be taken to mitigate the impacts from its Order. DOE will continue to track the impacts of its Order and public input and provide for appropriate mitigation where practicable. DOE will publish on its Web sites, as noted above, its discussion of which mitigation measures are

adopted for any future decision, and if not, why they are not adopted.

DOE may modify, in consultation with CEQ, the foregoing alternative arrangements as conditions warrant and will notify the public in the **Federal Register** if it does so.

Issued in Washington, DC, on January 18, 2006.

John Spitaleri Shaw,

Assistant Secretary for Environment, Safety and Health.

[FR Doc. 06-570 Filed 1-19-06; 8:45 am]

BILLING CODE 6450-01-P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 12481-002]

AMG Energy, LLC; Notice of Surrender of Preliminary Permit

January 12, 2006.

Take notice that AMG Energy, LLC, permittee for the proposed Selden Dam Project, has requested that its preliminary permit be terminated. The permit was issued on April 20, 2004, and would have expired on March 31, 2007.¹ The project would have been located on the Black Warrior River in Greene and Hale Counties, Alabama.

The permittee filed the request on December 7, 2005, and the preliminary permit for Project No. 12481 shall remain in effect through the thirtieth day after issuance of this notice unless that day is a Saturday, Sunday, part-day holiday that affects the Commission, or legal holiday as described in section 18 CFR 385.2007, in which case the effective date is the first business day following that day. New applications involving this project site, to the extent provided for under 18 CFR Part 4, may be filed on the next business day.

Magalie R. Salas,

Secretary.

[FR Doc. E6-598 Filed 1-19-06; 8:45 am]

BILLING CODE 6717-01-P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 12485-002]

AMG Energy, LLC; Notice of Surrender of Preliminary Permit

January 12, 2006.

Take notice that AMG Energy, LLC, permittee for the proposed Claiborne Hydroelectric Project, has requested that its preliminary permit be terminated. The permit was issued on June 28, 2004, and would have expired on May 31, 2007.¹ The project would have been located on the Alabama River in Monroe County, Alabama.

The permittee filed the request on December 7, 2005, and the preliminary permit for Project No. 12485 shall remain in effect through the thirtieth day after issuance of this notice unless that day is a Saturday, Sunday, part-day holiday that affects the Commission, or legal holiday as described in section 18 CFR 385.2007, in which case the effective date is the first business day following that day. New applications involving this project site, to the extent provided for under 18 CFR part 4, may be filed on the next business day.

Magalie R. Salas,

Secretary.

[FR Doc. E6-599 Filed 1-19-06; 8:45 am]

BILLING CODE 6717-01-P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. RP03-36-015]

Dauphin Island Gathering Partners; Notice of Negotiated Rate

January 13, 2006.

Take notice that on January 9, 2006, Dauphin Island Gathering Partners (Dauphin Island) tendered for filing as part of its FERC Gas Tariff, First Revised Volume No. 1, the revised tariff sheets listed below to become effective February 9, 2006.

Twenty-Fourth Revised Sheet No. 9.

Nineteenth Revised Sheet No. 10.

Seventh Revised Sheet No. 359.

Third Revised Sheet No. 427.

Dauphin Island states that these tariff sheets reflect changes to its statement of negotiated rates and nonconforming transportation and reserve commitment agreement tariff sheets.

¹ 107 FERC ¶ 62,053.

¹ 107 FERC ¶ 62,287.

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Department of Energy
Washington, DC 20585

January 18, 2006

Ms. Dinah Bear, General Counsel
Council on Environmental Quality
Executive Office of the President
722 Jackson Place, NW
Washington, DC 20503

Dear Ms. Bear:

The purpose of this letter is to document the Department of Energy's (DOE) consultations with the Council on Environmental Quality (CEQ) regarding compliance with the National Environmental Policy Act (NEPA) analyses and documentation requirements associated with the issuance of an emergency order under section 202(c) of the Federal Power Act (the Order) as a result of the shutdown of the Potomac River Generating Station (the Plant) in Alexandria, Virginia, on August 24, 2005. We thank you and others at CEQ for consulting with DOE on this matter on December 20 and 22, 2005, and January 13 and 17, 2006.

As you are aware, DOE issued its Order on December 20, 2005, requiring the owners of the Plant, Mirant Corporation and its wholly owned subsidiary, Mirant Potomac River, LLC (collectively referred to herein as Mirant), to generate electricity in certain limited circumstances. Due to the emergency nature of this matter, DOE issued the Order, despite potentially significant environmental impacts, without observing all of the normal provisions of the CEQ Regulations for Implementing the Procedural Requirements of the National Environmental Policy Act (NEPA) [40 CFR Parts 1500-1508]. Therefore, DOE is pursuing alternative arrangements to comply with NEPA, as provided in Section 1506.11 of the CEQ regulations. As a result of our discussions with CEQ, we propose the following alternative arrangements, which will expire October 1, 2006, unless extended:

1. Issuance of a *Federal Register* Notice, in accordance with DOE's NEPA regulations at 10 CFR 1021.343. The enclosed draft *Federal Register* Notice documents the emergency action that DOE has taken and actions it intends to pursue in the near term to address the electricity reliability emergency in the District of Columbia. The Notice provides background on Plant operations, outlines the Order DOE issued on December 20, 2005, and acknowledges potential environmental impacts from the Order. The Notice also describes DOE's continuing public involvement and preparation of a Special Environmental Analysis, as discussed below.
2. Prepare a Special Environmental Analysis (SEA). The SEA will examine potential impacts resulting from issuance of the Order, and describe further DOE decisionmaking regarding reasonable future alternatives and potential further



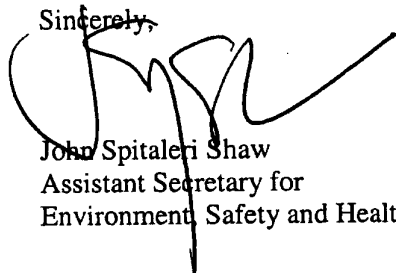
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mitigation actions DOE may take in this matter. The analysis will present reasonably foreseeable impacts from possible changes in operations of the Plant over the time until two additional transmission lines planned by Potomac Electric Power Company are installed. DOE intends to issue its SEA no later than August 2006 and will make it available to the public on the NEPA and Mirant matter websites as discussed in the enclosed Notice as well as announce its availability in the *Federal Register*. DOE will consider information contained in the SEA, and public input received on the SEA, in any future decisionmaking in this matter.

3. Provide Opportunities for Public Involvement. DOE is currently accepting public comments on the compliance plan that DOE required Mirant to submit under the DOE Order. DOE also invites public comments on this Notice as well as on issues to be addressed in the SEA. DOE will consider public input in determining appropriate mitigation measures and any additional actions DOE may take as DOE adaptively manages implementation of the Order. DOE will post on DOE's Mirant matter website publicly available information (not exempt from disclosure under the Freedom of Information Act) regarding the environmental effects of ongoing or alternative operations of the Plant (e.g., reasonably available ambient air quality data and results of air quality modeling) that the Department receives from Mirant, the Environmental Protection Agency (EPA), and the Virginia Department of Environmental Quality (DEQ).
4. Continue Agency Consultations. DOE will continue to consult with EPA and DEQ concerning information on emissions, modeling results, potential mitigation measures, and any changes to the operation of the Plant. EPA will act as a "cooperating agency" for purposes of providing reasonably available public information regarding the environmental effects of operations of the Plant to be disseminated via DOE's Mirant matter website and evaluated in the SEA.
5. Identify Mitigation. DOE will identify in its SEA any steps that it believes can be taken to mitigate the impacts from its Order. DOE will continue to track the impacts of its Order and public input and provide for appropriate mitigation where practicable. DOE will publish on its websites as noted above its discussion of which mitigation measures are adopted for any future decision, and if not, why they are not adopted.

We welcome any further suggestions you may have regarding our efforts to comply with NEPA under these emergency circumstances. Thank you for your assistance.

Sincerely,



John Spitaleri Shaw
Assistant Secretary for
Environment, Safety and Health

Enclosure



EXECUTIVE OFFICE OF THE PRESIDENT
COUNCIL ON ENVIRONMENTAL QUALITY
WASHINGTON, D.C. 20503

January 18, 2006

John Spitaleri Shaw
Assistant Secretary for
Environment, Safety and Health
Department of Energy
Washington, DC 20585

Dear Mr. Shaw:

This letter is in response to your January 18, 2006 letter documenting the Department of Energy's (DOE) request, under 40 C.F.R. 1506.11 and 10 CFR 1021.343, that the Council on Environmental Quality (CEQ) provide alternative arrangements for National Environmental Policy Act (NEPA) compliance. Consultation with CEQ is necessary to provide for a NEPA process that addresses the environmental effects of proposals for DOE action needed to maintain a minimally reliable electric power system for the central area of the District of Columbia (DC).

Your letter accurately reflects DOE's consultations with CEQ prior to and following issuance of its December 20, 2005 Order, which requires owners of the Potomac River Generating Station to generate electricity as necessary to address the current limitations of the electricity transmission system that serves central DC. The alternative arrangements proposed in your January 18, 2006 letter are limited to the immediate actions necessary to reduce electricity supply risks to acceptable levels, provide for local involvement and informed decision-making, and otherwise comply with NEPA in a manner appropriate to the nature and scope of the emergency described in the associated Federal Register notice.

Your proposal of alternative arrangements for NEPA compliance is accepted by CEQ. Thank you for your diligent coordination with CEQ. We plan to follow the implementation of these alternative arrangements closely and will remain available for consultation with DOE in this matter at any time.

Sincerely,

A handwritten signature in cursive script, reading "Dinah Bear", is written over a horizontal line.

Dinah Bear
General Counsel

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APPENDIX D

Consultation Letters with the U.S. Fish and Wildlife Service and the National Marine Fisheries Service

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August 17, 2006

U.S. Fish and Wildlife Service
Threatened and Endangered Species Branch
Chesapeake Bay Office
177 Admiral Cochrane Drive
Annapolis, MD 21401
ATTN: Mary Ratnaswamy

**RE: Informal Consultation under Section 7 of the Endangered Species Act (ESA)
for Operation of the Potomac River Generating Station in Alexandria,
Virginia, Pursuant to DOE Order.**

Dear Ms. Ratnaswamy:

This letter is intended to serve as informal consultation under section 7 of the ESA. In this regard, the Department of Energy (DOE) requests that you indicate if there are any additional protected species and habitat (beyond those described below) that should be considered for this ongoing action. If there are not any additional species or habitats and if you agree that the Plant would not impact any species when operating under the DOE Order, we request your concurrence that the operation of the Plant under the terms of the DOE Order would not adversely impact Federally listed or proposed threatened or endangered species or designated or proposed critical habitat and that the consultation requirements of section 7 of the ESA have been satisfied.

Background: On August 24, 2005, Mirant Corporation, and its wholly owned subsidiary, Mirant Potomac River, LLC (collectively referred to herein as Mirant), ceased operations at its Potomac River Generating Station (the "Plant") in Alexandria, Virginia, after modeling that it conducted indicated that the Plant's operations were causing exceedances of the National Ambient Air Quality Standards (NAAQS) of the Clean Air Act.

Also on August 24, 2005, the District of Columbia (D.C.) Public Service Commission filed an *Emergency Petition and Complaint* with DOE pursuant to section 202(c) of the Federal Power Act.

On December 20, 2005, after an exhaustive review of the facts and consultation with Federal and state officials responsible for environmental compliance and the private entities responsible for operation of the region's electrical grid, the Secretary of Energy issued an emergency order (the "Order") directing Mirant to generate electricity at the coal-fired Plant under certain, limited circumstances. On June 1, 2006, Mirant entered into an Administrative Consent Order (ACO) with the Environmental Protection Agency (EPA) regarding the operation of the Plant. On June 2, 2006, DOE instructed Mirant to comply with the ACO and operate as required under it.

After consultations with the Council on Environmental Quality (CEQ), DOE's Office of Electricity Delivery and Energy Reliability decided to prepare a special environmental analysis (SEA) under the emergencies provision of CEQ's National Environmental Policy Act (NEPA) Implementing Regulations (40 CFR 1506.11) and the emergency circumstances provision of DOE's own NEPA implementing regulations [10 CFR 1021.343(a)]. The SEA will document the assessment of the impacts associated with the emergency activities under DOE Order 202-05-03. The time period for DOE's Order extends to October 1, 2006; however, the SEA also addresses the 15-month period from October 1, 2006, through December 31, 2007, at which time new transmission lines are expected to be available to provide a high level of electric reliability to customers in the Central D.C. area, even in the absence of production from the Plant.

The Plant: The Potomac River Generating Station began operation in 1949 and is capable of producing 482 megawatts of electric power. The Plant site encompasses 28 acres (11 has) near D.C. and Reagan National Airport on the western bank of the Potomac River (Figure 1). Most of the property is used for power generation, coal storage, office buildings, and parking areas. The site was relatively remote when the power plant was built, but Alexandria has grown up around it. The Plant is beneath the flight path of Reagan National Airport.

EPA issued a National Pollutant Discharge Elimination System (NPDES) permit to the Plant on April 20, 2000, authorizing discharges into the Potomac River. The Virginia Department of Environmental Quality approved a Stationary Source Permit to Operate on September 18, 2000, and a Phase II Acid Rain Permit on February 23, 2003.

Coal combustion ash from the Plant is sent to the Brandywine Fly Ash Facility, which is located in southeastern Prince George's County, Maryland (Figure 2). Water from this landfill discharges into the upper reaches of Mataponi Creek.

Action at the Plant under DOE's Order: The DOE Order resulted in no new disturbances from construction at the Plant site. The provisions of DOE's Order and subsequent instructions to Mirant have, however, caused changes in the level of operation at the Plant. These changes have reduced the operating level of the Plant to below that at which it was historically operating before August 24, 2005, but increased the operating level above that at which it was operating between August 24 and December 20, 2005. To reduce sulfur dioxide (SO₂) emissions, Mirant has been using a compound known as "trona" (sodium sesquicarbonate, a naturally occurring substance similar to baking soda) and/or lower sulfur coal. Thus, even if the Plant were operating at the same level as before August 24, 2005, its emissions of SO₂ would be lower.

Threatened and Endangered (T&E) Species Impacts: Because the Plant site is heavily industrialized and surrounded by development in the City of Alexandria, no Federally listed or proposed threatened or endangered species are known or likely to occur on the Plant site. Also, there is no known designated or proposed critical habitat in the area of the action.

Of the permits issued for the Plant or landfill, only the NPDES permit for the Plant mentions T&E species. That permit states that two species listed by the U.S. Fish and Wildlife Service (FWS) under the ESA occur or may occur at locations near the Plant. These are the endangered Hay's Spring amphipod (*Stygobromus hayi*) and the threatened bald eagle (*Haliaeetus leucocephalus*).

The Plant's NPDES permit states, "The FWS and NMFS indicate that at the present time [i.e., April 20, 2000] there is no evidence that the ongoing wastewater discharges covered by this permit are adversely affecting these Federally listed species." Furthermore, "(w)astewater discharges, construction, or any other activity that adversely affects a Federally listed endangered or threatened species are [sic] not authorized under the terms of this permit."

The Hay's Spring amphipod occurs only in a small area in Rock Creek in D.C. The bald eagle is unlikely to occur near the Plant as the area around it is developed and provides no suitable habitat. There has been no known impact to these species due to the Plant's operation prior to the DOE Order. Thus, since there has been no impact to Federally listed threatened or endangered species when the Plant was operating at the higher historical level before August 24, 2005, adverse impacts to such species from the lower level of operation at the Plant under DOE's Order would not be expected.

Since the DOE Order is scheduled to expire on October 1, 2006, receipt of your reply and/or concurrence before that date will allow DOE to consider your comments in determining what, if any, future actions to take in this matter.

If you need additional information or wish to discuss this matter further, please contact me at (202) 586-5935.

Sincerely,

Anthony J. Como
Director, Permitting and Siting
Office of Electricity Delivery and
Energy Reliability
U.S. Department of Energy

Enclosures (2)

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August 17, 2006

Northeast Regional Office
National Marine Fisheries Service
Protected Resource Division
One Blackburn Drive
Gloucester, MA 01930
Attn: Julie Crocker

**RE: Informal Consultation under Section 7 of the Endangered Species Act (ESA)
for Operation of the Potomac River Generating Station in Alexandria,
Virginia, Pursuant to DOE Order.**

Dear Ms. Crocker:

This letter is intended to serve as informal consultation under section 7 of the ESA. In this regard, the Department of Energy (DOE) requests that you indicate if there are any additional protected species and habitat (beyond those described below) that should be considered for this ongoing action. If there are not any additional species or habitats and if you agree that the Plant would not impact any species when operating under the DOE Order, we request your concurrence that the operation of the Plant under the terms of the DOE Order would not adversely impact Federally listed or proposed threatened or endangered species or designated or proposed critical habitat and that the consultation requirements of section 7 of the ESA have been satisfied.

Background: On August 24, 2005, Mirant Corporation, and its wholly owned subsidiary, Mirant Potomac River, LLC (collectively referred to herein as Mirant), ceased operations at its Potomac River Generating Station (the "Plant") in Alexandria, Virginia, after modeling that it conducted indicated that the Plant's operations were causing exceedances of the National Ambient Air Quality Standards (NAAQS) of the Clean Air Act.

Also on August 24, 2005, the District of Columbia (D.C.) Public Service Commission filed an *Emergency Petition and Complaint* with DOE pursuant to section 202(c) of the Federal Power Act.

On December 20, 2005, after an exhaustive review of the facts and consultation with Federal and state officials responsible for environmental compliance and the private entities responsible for operation of the region's electrical grid, the Secretary of Energy issued an emergency order (the "Order") directing Mirant to generate electricity at the coal-fired Plant under certain, limited circumstances. On June 1, 2006, Mirant entered into an Administrative Consent Order (ACO) with the Environmental Protection Agency (EPA) regarding the operation of the Plant. On June 2, 2006, DOE instructed Mirant to comply with the ACO and operate as required under it.

After consultations with the Council on Environmental Quality (CEQ), DOE's Office of Electricity Delivery and Energy Reliability decided to prepare a special environmental analysis (SEA) under the emergencies provision of CEQ's National Environmental Policy Act (NEPA) Implementing Regulations (40 CFR 1506.11) and the emergency circumstances provision of DOE's own NEPA implementing regulations [10 CFR 1021.343(a)]. The SEA will document the assessment of the impacts associated with the emergency activities under DOE Order 202-05-03. The time period for DOE's Order extends to October 1, 2006; however, the SEA also addresses the 15-month period from October 1, 2006, through December 31, 2007, at which time new transmission lines are expected to be available to provide a high level of electric reliability to customers in the Central D.C. area, even in the absence of production from the Plant.

The Plant: The Potomac River Generating Station began operation in 1949 and is capable of producing 482 megawatts of electric power. The Plant site encompasses 28 acres (11 ha) near the D.C. and Reagan National Airport on the western bank of the Potomac River (Figure 1). Most of the property is used for power generation, coal storage, office buildings, and parking areas. The site was relatively remote when the power plant was built, but Alexandria has grown up around it. The Plant is beneath the flight path of Reagan National Airport.

EPA issued a National Pollutant Discharge Elimination System (NPDES) permit to the Plant on April 20, 2000, authorizing discharges into the Potomac River. The Virginia Department of Environmental Quality approved a Stationary Source Permit to Operate on September 18, 2000, and a Phase II Acid Rain Permit on February 23, 2003.

Coal combustion ash from the Plant is sent to the Brandywine Fly Ash Facility, which is located in southeastern Prince George's County, Maryland (Figure 2). Water from this landfill discharges into the upper reaches of Mataponi Creek.

Action at the Plant under DOE's Order: The DOE Order resulted in no new disturbances from construction at the Plant site. The provisions of DOE's Order and subsequent instructions have, however, caused changes in the level of operation at the Plant. These changes have reduced the operating level of the Plant to below that at which it was historically operating before August 24, 2005, but increased the operating level above that at which it was operating between August 24 and December 20, 2005. To reduce sulfur dioxide (SO₂) emissions, Mirant has been using a compound known as "trona" (sodium sesquicarbonate, a naturally occurring substance similar to baking soda) and/or lower sulfur coal. Thus, even if the Plant were operating at the same level as before August 24, 2005, its emissions of SO₂ would be lower.

Threatened and Endangered (T&E) Species Impacts: Because the Plant site is heavily industrialized and surrounded by development in the City of Alexandria, no Federally listed or proposed threatened or endangered species are known or likely to occur on the Plant site. Also, there is no known designated or proposed critical habitat in the area of the action.

Of the permits issued for the Plant or landfill, only the NPDES permit for the Plant mentions T&E species. That permit states that one species listed by the National Marine Fisheries Service (NMFS) under the ESA, the endangered shortnose sturgeon (*Acipenser brevirostrum*), occurs or may occur at locations near the Plant.

The Plant's NPDES permit states, "The FWS and NMFS indicate that at the present time [i.e., April 20, 2000] there is no evidence that the ongoing wastewater discharges covered by this permit are adversely affecting these Federally listed species." Furthermore, "(w)astewater discharges, construction, or any other activity that adversely affects a Federally listed endangered or threatened species are [sic] not authorized under the terms of this permit."

The Shortnose Sturgeon Recovery Plan reports that one shortnose sturgeon was captured in 1996 at the mouth of Potomac Creek off the Potomac River downstream from the Plant. However, there are no other recent reports of it occurring in the Potomac River; therefore, there has been no known impact to this species due to the Plant's operation prior to the DOE Order. Since there has been no known impact to Federally listed threatened or endangered species when the Plant was operating at the higher historical level before August 24, 2005, adverse impacts to such species from the lower level of operation at the Plant under DOE's Order would not be expected.

Since the DOE Order is scheduled to expire on October 1, 2006, receipt of your reply and/or concurrence before that date will allow DOE to consider your comments in determining what, if any, future actions to take in this matter.

If you need additional information or wish to discuss this matter further, please contact me at (202) 586-5935.

Sincerely,

Anthony J. Como
Director, Permitting and Siting
Office of Electricity Delivery and
Energy Reliability
U.S. Department of Energy

Enclosures (2)

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UNITED STATES DEPARTMENT OF COMMERCE
National Oceanic and Atmospheric Administration
NATIONAL MARINE FISHERIES SERVICE
NORTHEAST REGION
One Blackburn Drive
Gloucester, MA 01930-2298

OCT - 3 2006

Anthony J. Como, Director
Permitting and Siting
Office of Electricity Delivery and Energy Reliability
US Department of Energy
Washington, DC 20585

Dear Mr. Como,

This is in response to your letter dated August 17, 2006 requesting consultation pursuant to Section 7 of the Endangered Species Act (ESA) of 1973, as amended, regarding the operation of Mirant's Potomac River Generating Station in Alexandria, Virginia.

The Potomac River Generating Station is a coal fired plant located on the western bank of the Potomac River. The Plant began operation in 1949. On August 24, 2005, Mirant ceased operations at its Plant after modeling indicated that the Plant's operations were causing exceedences of the National Ambient Air Quality Standards of the Clean Air Act. On December 20, 2005, the Secretary of Energy issued an emergency order directing Mirant to generate electricity at the Plant under certain circumstances. On June 1, 2006, Mirant entered into an Administrative Consent Order (ACO) with the US Environmental Protection Agency (EPA) regarding the operation of the Plant. The DOE requires the Plant to operate at lower levels and to reduce sulfur dioxide emissions by using a compound known as "trona" (sodium sesquicarbonate) and/or lower sulfur coal. On June 2, 2006, the Department of Energy (DOE) instructed Mirant to comply with the ACO and operate as required under it. Operation of the Plant is necessary to ensure an uninterrupted supply of electricity to the District of Columbia. DOE has indicated that its order to comply with the ACO is scheduled to expire on October 1, 2006. The operation of the Plant from October 1, 2006 through summer 2007 under the terms of the DOE Order is the subject of this consultation. The DOE has made the determination that the operation of the Plant under the Order is not likely to adversely affect any species listed under the jurisdiction of NOAA's National Marine Fisheries Service (NMFS) and has requested that NMFS concur with this determination.

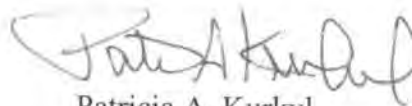
As noted in your letter, the only species listed under the jurisdiction of NMFS that may be present in the vicinity of the proposed project is the endangered shortnose sturgeon (*Acipenser brevirostrum*). During the 1996-2005 time period, the incidental capture of seventy-two different shortnose sturgeon in the Chesapeake Bay and its tributaries had been reported via the US Fish and Wildlife Service Atlantic sturgeon reward program. This number includes six shortnose sturgeon captured incidentally in fishing gear in the Potomac River. Additionally, researchers conducting a survey for shortnose sturgeon in the river captured one mature egg bearing female



in September 2005 and an additional mature egg bearing female in the same location in March 2006. Both fish have been outfitted with sonic tags and are being actively tracked by researchers. The female caught in September overwintered in the Potomac River near Mattawoman Creek. One of the females was documented at the presumed spawning grounds near Little Falls in the spring of 2006. The occurrence of pre-spawning females in the Potomac River suggests that a spawning population of shortnose sturgeon continues to exist in this river system. The Plant is located approximately 24 miles upstream of the suspected overwintering area. Population dynamics of shortnose sturgeon in the Potomac River have not been documented. However, based on patterns in other river systems, shortnose sturgeon likely migrate past the Plant while moving to and from the spawning grounds near Little Falls in the spring (March – June). It is unknown if shortnose sturgeon would occur in this region of the river during other times of the year. If appropriate forage items are present, shortnose sturgeon could also occur in the area in the summer and fall while foraging.

The continuation of operations from October 1, 2006 through summer 2007, would not result in any new construction or in-water disturbances at the plant. The only aspect of the Plant's continued operation that has the potential to impact shortnose sturgeon is the discharge of waste water from the Plant to the Potomac River. These discharges are authorized under a NPDES permit issued by the EPA. NMFS has previously consulted with the EPA on the NPDES permit for the Plant and determined that the discharges are not likely to adversely affect shortnose sturgeon. While the past operation of the plant has resulted in air quality impairments, there is no information available that indicates that the operation of the plant has had an adverse effect on water quality in the Potomac River. No other impacts from the operation of the Plant under the DOE order are likely. As such, NMFS concurs with DOE's determination that the continued operation of the Plant through summer 2007 is not likely to adversely affect any species listed under NMFS jurisdiction. Therefore, no further consultation pursuant to section 7 of the ESA is required. Should project plans change or new information become available that changes the basis for this determination, or a new species be listed or critical habitat designated, consultation should be reinitiated. Should you have any questions about this correspondence please contact Julie Crocker at (978) 281-9300 ext. 6530.

Sincerely,



Patricia A. Kurkul
Regional Administrator

Cc: Scida, F/NER3
Nichols, F/NER4
Williams, GCNE



United States Department of the Interior

FISH AND WILDLIFE SERVICE
Chesapeake Bay Field Office
177 Admiral Cochrane Drive
Annapolis, MD 21401
410/573-4575



November 20, 2006

*RE: Informal Consultation under Section 7 of the Endangered Species Act (ESA) for
Operation of the Potomac River generating Station in Alexandria, Va.*

Dear Mr. Como,

This responds to your letter, received November 20, 2006, requesting information on the presence of species which are federally listed or proposed for listing as endangered or threatened in the above referenced project area. We have reviewed the information you enclosed and are providing comments in accordance with section 7 of the Endangered Species Act (87 Stat. 884, as amended; 16 U.S.C. 1531 *et seq.*).

Except for occasional transient individuals, no proposed or federally listed endangered or threatened species are known to exist within the project impact area. Therefore, no Biological Assessment or further section 7 consultation with the U.S. Fish and Wildlife Service is required. Should project plans change, or should additional information on the distribution of listed or proposed species become available, this determination may be reconsidered.

This response relates only to federally protected threatened or endangered species under our jurisdiction. Limited information is currently available regarding the distribution of other rare species in the District of Columbia. However, the Nature Conservancy and National Park Service (NPS) have initiated an inventory of rare species within the District. For further information on such rare species, you should contact Mary Pfaffko of the National Park Service at (202)-535-1739.

An additional concern of the Service is wetlands protection. Federal and state partners of the Chesapeake Bay Program have adopted an interim goal of no overall net loss of the Basin's remaining wetlands, and the long term goal of increasing the quality and quantity of the Basin's wetlands resource base. Because of this policy and the functions and values wetlands perform, the Service recommends avoiding wetland impacts. All wetlands within the project area should be identified, and if alterations of wetlands is proposed, the U.S. Army Corps of Engineers, Baltimore District, should be contacted for permit requirements. They can be reached at (410) 962-3670.

We appreciate the opportunity to provide information relative to fish and wildlife issues, and

thank you for your interests in these resources. If you have any questions or need further assistance, please contact Devin Ray at (410) 573-4531.

Sincerely,

A handwritten signature in cursive script that reads "Mary Ratnaswamy".

Mary J. Ratnaswamy, Ph.D.

Program Supervisor, Threatened and Endangered Species

APPENDIX E

Organizational Conflict of Interest Statement

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**NEPA DISCLOSURE STATEMENT FOR PREPARATION OF A
SPECIAL ENVIRONMENTAL ANALYSIS FOR ACTIONS TAKEN UNDER
DOE ORDER 202-05-3 REGARDING OPERATION OF THE POTOMAC RIVER
GENERATING STATION IN ALEXANDRIA, VIRGINIA**

CEQ Regulations at 40 CFR 1506.5(c), which have been adopted by the DOE (10 CFR 1021), require contractors who will prepare an environmental impact statement to execute a disclosure specifying that they have no financial or other interest in the outcome of the project. The term "financial interest or other interest in the outcome of the project" for purposes of this disclosure is defined in the March 23, 1981, guidance "Forty Most Asked Questions Concerning CEQ's National Environmental Policy Act Regulations," 46 FR 18026-18038 at Question 17a and b.

"Financial or other interest in the outcome of the project" includes "any financial benefit such as a promise of future construction or design work in the project, as well as indirect benefits the contractor is aware of (e.g., if the project would aid proposals sponsored by the firm's other clients)." 46 FR 18026-10838 at 10831.

In accordance with these requirements, the offeror and any proposed subcontractors hereby certify as follows: [check either (a) or (b) to assure consideration of your proposal].

- (a) X Offeror and any proposed subcontractor have no financial or other interest in the outcome of the project.
- (b) Offeror and any proposed subcontractor have the following financial or other interest in the outcome of the project and hereby agree to divest themselves of such interest prior to award of this contract.

Financial or Other Interests

- 1.
- 2.
- 3.

Certified by:



Signature

Gary K. Jacobs,
Director, Environmental Sciences Division
Printed Name and Title

Oak Ridge National Laboratory,
Managed for the U.S. Department of Energy
by UT-Battelle, LLC
Company

11-1-06

Date

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APPENDIX F

Glossary

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GLOSSARY

Anadromous - species that spend their adult lives in saltwater and spawn in freshwater.

Ash - the mineral content of a product remaining after complete combustion.

Baseload - generating units that produce power at a steady rate for extended periods.

Biochemical oxygen demand - a standard quantitative measure of water pollution. It is the amount of oxygen consumed in the biological oxidation (by bacteria or other microorganisms) of organic material in a unit volume of waste water, as measured over a five-day period.

Biochemical oxygen demand sometimes is divided into two components: carbonaceous oxygen demand and nitrogenous oxygen demand. Carbonaceous biochemical oxygen demand is the result of the breakdown of organic molecules such as cellulose and sugars, while nitrogenous oxygen demand is the result of the breakdown of proteins.

Biocide - a substance (e.g., chlorine) that is toxic or lethal to many organisms and is used to treat water.

Blowdown - the portion of steam or water removed from a boiler at regular intervals to prevent excessive accumulation of dissolved and suspended materials.

Bottom ash - combustion residue composed of large particles that settle to the bottom of a combustor from where they can be physically removed.

Calcining - the effects of heating a substance to a high temperature (below the melting or fusing point) at which point loss of moisture, reduction or oxidation, or the decomposition of carbonates and other compounds occurs.

Candidate species - plants and animals native to the United States for which the Fish and Wildlife Service or the National Marine Fisheries Service has sufficient information on biological vulnerability and threats to justify proposing to add them to the threatened and endangered species list, but cannot do so immediately because other species have a higher priority for listing. The Services determine the relative listing priority of candidate taxa in accordance with general listing priority guidelines published in the *Federal Register*. (See endangered species and threatened species.)

Cooling water - water that is heated as a result of being used to cool steam and condense it to water.

Cyanobacteria - blue-green algae.

Diadromous - fish spending part of their lives in both fresh and salt water.

Downwash (building) - the downward movement of an elevated plume toward the area of low pressure created on the lee side of a structure in the wake around which the air flows.

Electrostatic precipitator - a device that removes particles from a stream of exhaust gas. It imparts an electrical charge to the particles, which causes them to adhere to metal plates that can be rapped to cause the particles to fall into a hopper for disposal.

Endangered species - plants or animals that are in danger of extinction through all or a significant portion of their ranges and that have been listed as endangered by the Fish and Wildlife Service or the National Marine Fisheries Service following the procedures outlined in the Endangered Species Act and its implementing regulations (50 CFR 424). (See threatened species.) The lists of endangered species can be found in 50 CFR 17.11 (wildlife), 50 CFR 17.12 (plants), and 50 CFR 222.23(a) (marine organisms). The state of Virginia also lists species as endangered under its Endangered Species Act.

Entrainment - incorporation of any life stage of fish and shellfish with water flow entering and passing through a cooling water intake structure and into an industrial, municipal or electric utility power plant cooling water system.

Estuary - region of interaction between rivers and near-shore ocean waters, where tidal action and river flow mix fresh and salt water. Such areas include bays, mouths of rivers, salt marshes, and lagoons. These brackish water ecosystems shelter and feed marine life, birds, and wildlife. (See wetlands.)

Fall line - the boundary zone where the upland piedmont region meets the coastal plain. Waterfalls and rapids occur where rivers and streams cross the fall line.

Finfish - a fish with fins (which is most fish), in contrast to shellfish, crayfish, and jellyfish (which are not fish).

Fly ash - combustion residue composed of fine particles (e.g., soot) that are entrained with the draft leaving the combustor.

Fresh water - water with a low concentration of salts (typically less than 1,000 parts per million of dissolved solids).

Hazardous waste - a category of waste regulated under the Resource Conservation and Recovery Act (RCRA). To be considered hazardous, a waste must be a solid waste under RCRA and must exhibit at least one of four characteristics described in 40 CFR 261.20 through 40 CFR 261.24 (i.e., ignitability, corrosivity, reactivity, or toxicity) or be specifically listed by the Environmental Protection Agency in 40 CFR 261.31 through 40 CFR 261.33.

Impingement - the entrapment of any life stage of fish and shellfish on the outer part of an intake structure or against a screening device during intake water withdrawal.

Leachate - solution or product obtained by leaching, in which a substance is dissolved by the action of a percolating liquid.

Load following - power generating units that are capable of changing power levels quickly as demand rises or falls. They are also known as cycling units.

pH - a measure of the relative acidity or alkalinity of a solution, expressed on a scale from 0 to 14, with the neutral point at 7. Acid solutions have pH values lower than 7, and basic (i.e., alkaline) solutions have pH values higher than 7.

Plume (atmospheric) - a visible or measurable, elongated pattern of emissions spreading downwind from a source through the atmosphere.

Pozzolanitic - material that when mixed with water “sets,” like cement.

Riparian - areas adjacent to rivers and streams with a differing density, diversity, and productivity of plant and animal species relative to nearby uplands.

Saline - describes water with high concentrations of salts (typically more than 10,000 parts per million dissolved solids), making it unsuitable for use.

Stratosphere - the portion of the atmosphere 10 to 25 mi (16 to 40 km) above the earth's surface.

Threatened species - any plants or animals that are likely to become endangered species within the foreseeable future throughout all or a significant portion of their ranges and which have been listed as threatened by the Fish and Wildlife Service or the National Marine Fisheries Service following the procedures set out in the Endangered Species Act and its implementing regulations (50 CFR 424). (See endangered species.) The lists of threatened species can be found at 50 CFR 17.11 (wildlife), 17.12 (plants), and 227.4 (marine organisms). The state of Virginia also lists species as threatened under its Endangered Species Act.

Tidal river - a river segment with fresh water (salinity less than 500 mg/L) and a net seaward flow direction throughout the water column.

Transmission (electric) - movement of electrical power from the source where it is produced to end users.

Trona - a naturally occurring chemical compound, sodium sesquicarbonate, similar to baking soda.

Troposphere - the layer of the atmosphere closest to the earth's surface.

Watershed - the region draining into a river, river system, or other body of water.

Wetlands - areas that are inundated or saturated by surface water or groundwater at a frequency and duration sufficient to support, and that under normal circumstances do support, a prevalence of vegetation typically adapted for life in saturated soil conditions, including swamps, marshes, bogs, and similar areas.

Wind rose - a graph in which the frequency of wind blowing from each direction is plotted as a bar that extends from the center of the diagram. Wind speeds are denoted by bar widths and shading; the frequency of wind speed within each wind direction is depicted according to the length of that section of the bar.

Attachment I

MPSC Case No. U-21090, Settlement Agreement

April 20, 2022

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

General Offices:

One Energy Plaza
Jackson, MI 49201

Tel: (517) 788-0550
Fax: (517) 768-3644

*Washington Office:

1730 Rhode Island Ave. N.W.
Suite 1007
Washington, DC 20036

Tel: (202) 778-3340
Fax: (202) 778-3355

Writer's Direct Dial Number: (517) 788-1846

Writer's E-mail Address: robert.beach@cmsenergy.com

LEGAL DEPARTMENT

SHAUN M. JOHNSON
Senior Vice President
and General Counsel

MELISSA M. GLEESPEEN
Vice President, Corporate
Secretary and Chief
Compliance Officer

KELLY M. HALL
Vice President and Deputy
General Counsel

Emerson J. Hilton
Adam C. Smith
Bret A. Totoraitis
Assistant General Counsel

Robert W. Beach
Ian F. Burgess
Don A. D'Amato
Gary A. Gensch, Jr.
Matthew D. Hall
Georgine R. Hyden
Katie M. Knue
Robert F. Marvin
Jason M. Milstone
Rhonda M. Morris
Deborah A. Moss*
Maxwell K. Multer
Chantez L. Pattman
Michael C. Rampe
Scott J. Sinkwitz
Theresa A.G. Staley
Janae M. Thayer
Anne M. Uitvlugt
Aaron L. Vorce
Attorney

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:

Pursuant to Rule 431, R 792.10431, enclosed for electronic filing in the above-captioned proceeding, please find a **Settlement Agreement** which is intended to resolve all outstanding issues in this proceeding. The Settlement Agreement has been executed by Consumers Energy Company, the Michigan Public Service Commission Staff, Michigan Environmental Council, the Natural Resources Defense Council, the Sierra Club, Attorney General Dana Nessel, Environmental Law and Policy Center, Vote Solar, Ecology Center, Union of Concerned Scientists, Urban Core Collective, Citizens Utility Board of Michigan, Hemlock Semiconductor Operations, LLC, Michigan Energy Innovation Business Council, Institute for Energy Innovation, Clean Grid Alliance, Michigan Electric Transmission Company, LLC, and Great Lakes Renewable Energy Association.

Also included are the signatures of the following parties who do not join the settlement but are offering a statement of non-objection: Michigan Public Power Agency and Midland Cogeneration Venture, LP.

Energy Michigan Inc., Wolverine Power Supply Cooperative Inc., the Mackinac Center for Public Policy, Residential Customer Group, the Biomass Merchant Plants¹, and the Association of Businesses Advocating Tariff Equity have not signed the settlement and have not indicated that they will sign a statement of non-objection.

The Company respectfully requests that, pursuant to Rule 431(3), the Commission establish a reasonable time for response to this submittal, but in no event later than 14 days from April 20, 2022.

¹ The BMPs consist of: Cadillac Renewable Energy, LLC, Genesee Power Partners Limited Partnership, Decker Energy-Grayling, LLC, Hillman Power Company, LLC, Tondu Corporation, National Energy of Lincoln, LLC, f/k/a Viking Energy of Lincoln, LP and National Energy of McBain, f/k/a Viking Energy of McBain, LLC.

This is a paperless filing and is therefore being filed only in PDF. I have enclosed a Proof of Service showing electronic service upon the parties.

Sincerely,

A handwritten signature in black ink, appearing to read 'RWB', with a horizontal line extending to the right.

Digitally signed by
Robert W. Beach
Date: 2022.04.20 09:59:15
-04'00'

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	)	Case No. U-21090
under MCL 460.6t, certain accounting	)	
approvals, and for other relief.	)	
_____	)	

SETTLEMENT AGREEMENT

Pursuant to MCL 24.278 and Rule 431 of the Michigan Administrative Hearing System’s Rules of Practice and Procedure before the Michigan Public Service Commission (“MPSC” or the “Commission”), the undersigned parties agree as follows:

WHEREAS, on June 30, 2021 Consumers Energy Company (“Consumers Energy” or the “Company”) filed an Application requesting approval of the Company’s Integrated Resource Plan (“IRP”) pursuant to Section 6t of 2016 PA 341, MCL 460.6t, the Commission’s June 7, 2019 Order Approving Settlement Agreement in Case No. U-20165, and all other orders and applicable law. The Company filed testimony and exhibits in support of its positions concurrently with its Application.

WHEREAS, the initial prehearing conference was held on July 22, 2021 before Administrative Law Judge (“ALJ”) Sally L. Wallace. Beyond the Company, the parties to the IRP are: the MPSC Staff (“Staff”); the Attorney General; Hemlock Semiconductor Operations, LLC (“HSC”); the Biomass Merchant Plants (“BMPs”)¹; Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club (“MNS”); Great Lakes Renewable Energy

¹ The BMPs consist of: Cadillac Renewable Energy, LLC, Genesee Power Partners Limited Partnership, Decker Energy-Grayling, LLC, Hillman Power Company, LLC, Tondur Corporation, National Energy of Lincoln, LLC, f/k/a Viking Energy of Lincoln, LP and National Energy of McBain, f/k/a Viking Energy of McBain, LLC.

Association (“GLREA”), Environmental Law and Policy Center, the Ecology Center, Vote Solar, and the Union of Concerned Scientists (collectively, the Clean Energy Organizations (“CEO”)); Residential Customer Group (“RCG”); Association of Businesses Advocating Tariff Equity (“ABATE”); Michigan Energy Innovation Business Council, Institute for Energy Innovation, and the Clean Grid Alliance (collectively, “Michigan EIBC/IEI/CGA”); Energy Michigan, Inc. (“Energy Michigan”); Midland Cogeneration Venture Limited Partnership (“MCV”); Michigan Electric Transmission Company, LLC (“METC”); Michigan Public Power Agency (“MPPA”); Wolverine Power Supply Cooperative (“Wolverine”); the Citizens Utility Board (“CUB”); the Mackinac Center for Public Policy (“Mackinac”); and the Urban Core Collective (“UCC”). 1 TR 11-12, 22.

WHEREAS, Consumers Energy filed testimony and exhibits requesting approval of the Company’s IRP Proposed Course of Action (“PCA”) in its entirety, as the most reasonable and prudent means of meeting the Company’s energy and capacity needs through 2040. The Company specifically requested the Commission to make the following determinations:

- (i.) Approve Consumers Energy’s PCA, which is inclusive of all proposals presented by the Company in this case, including the battery deployment program, as the most reasonable and prudent means of meeting the energy and capacity needs of the Company and its customers;
- (ii.) Approve the Company’s acquisition and proposed purchase costs for the New Covert Generating Facility (“Covert Plant”) and Dearborn Industrial Generation (“DIG Plant”), the Livingston Generating Station (“Livingston Plant”), and the Kalamazoo River Generating Station (“Kalamazoo Plant”), in the manner proposed by the Company, and proposed Energy Waste Reduction (“EWR”), Demand Response (“DR”), and Conservation Voltage Reduction (“CVR”) costs which will be commenced by the Company within three years following the Commission’s expected approval of the Company’s IRP;
- (iii.) Approval of the selection and proposed purchase of the DIG, Kalamazoo, and Livingston plants, by the Company from its affiliate, CMS Enterprises. The transaction was a result of a competitive solicitation and is compliant with the Commission’s Code of Conduct requirements. In the alternative, while complying with all other provisions of the Code of Conduct, the Company

requests a waiver of the asset transfer provision of the Code of Conduct, Mich Admin Code R 460.10108(4), for the acquisition of the DIG, Livingston, and Kalamazoo plants, from CMS Enterprises;

- (iv.) Approve the Company's proposal to recover the unrecovered book balances of D.E. Karn ("Karn") Units 3 and 4 and J.H. Campbell ("Campbell") Units 1, 2, and 3, including decommissioning costs, through regulatory asset treatment, with full return, over the design lives of those units;
- (v.) Approve the Company's proposals to: (i) defer employee retention costs related to the proposed accelerated retirements of Karn Units 3 and 4 and Campbell Units 1, 2, and 3, and (ii) defer retirement transition costs for future recovery;
- (vi.) Approve the Company's proposed modifications to its Public Utility Regulatory Policies Act of 1978 ("PURPA") construct and the Company's proposed competitive procurement process and the use of that competitive procurement process for: (i) determining PURPA avoided costs rates, and (ii) determining and addressing the Company's capacity position under PURPA;
- (vii.) Determine that the Company has no PURPA capacity need so long as the Company is implementing the PCA, with the competitive procurement process proposed by the Company; and
- (viii.) Approve the Company's proposed Financial Compensation Mechanism ("FCM") for any new, or newly amended, Power Purchase Agreements ("PPAs") entered into by the Company.

Staff and other intervening parties filed testimony and exhibits addressing various issues.

NOW THEREFORE, for purposes of settlement of Case No. U-21090, the undersigned parties agree as follows:

1. The parties agree that the Company's PCA, as modified in this Settlement Agreement, should be approved as the most reasonable and prudent means of meeting the Company's energy and capacity needs over the 5-year, 10-year, and 15-year time horizons. The parties agree that the Company will file its next IRP consistent with the requirements of MCL 460.6t.

2. The parties agree that the PCA shall include the Company's proposed purchase of the Covert Plant in 2023 but shall not include the ownership of the DIG, Kalamazoo, and

Livingston plants. The parties agree that the identified capital costs that the Company will incur for DR (\$23,751,000), CVR (\$9,736,315), and the purchase of the Covert Plant (\$815 million) in the next three years (June 2022 – June 2025) are reasonable and prudent and approved for cost recovery purposes and will be included in rates in a future Company rate case consistent with MCL 460.6t(11) and (17). The parties further agree to the approval of the projected capacity value provided by the Covert Plant and the DR (projected to achieve a total of 641 MW (657 Zonal Resource Credits (“ZRCs”)) by 2025), CVR (projected to achieve 136,351 MWh savings by 2025, 56.81 MW savings by 2025), and EWR (projected to achieve 545,305 MWh savings in 2025, 879 MW savings by 2025) resources included in the PCA during the next three years. The parties further agree that the Company shall continue to file an annual reporting template with the Commission addressing the implementation of the approved DR and CVR resources above.

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

4. The parties agree that (i) Karn Units 3 and 4 will be retired on or before May 31, 2031, absent extraordinary circumstances that require prolonged operation, such as a System Support Resource designation by Midcontinent Independent System Operator, Inc. (“MISO”) or other emergent issues within the Company’s generation portfolio which require continued

operation of Karn Units 3 and 4 to maintain sufficient supply; and (ii) Campbell Units 1, 2, and 3 will be retired on or before May 31, 2025.

5. The parties agree that the Company will not file an application for a financing order for the unrecovered book balance and decommissioning costs of Campbell Units 1, 2, and 3. The parties agree that the Commission will permit Consumers Energy to recover the unrecovered book balance of Campbell Units 1, 2, and 3 through the Company's proposed regulatory asset treatment, with a return equal to the Company's weighted average cost of capital ("WACC") premised on the return on equity approved by the Commission in rate cases prior to the retirement date of those units and a 9.0% return on equity after the retirement date of those units, as part of the Company's electric rates over the current design lives of those units. The 9.0% return on equity will be used to modify the capital structure filed with each rate case and the return on equity will be the only modification to the capital structure used to calculate the return on the regulatory asset after the retirement date of the units. The parties further agree that the Company will be permitted to record a regulatory asset for actual decommissioning spending for Campbell Units 1, 2, and 3, with a return on the regulatory asset, with subsequent rate recovery in a rate case after a review of the reasonableness and prudence of the expenses. Recovery of the associated decommissioning and ash disposal costs will be treated as follows:

- a. The decommissioning costs, less salvage value, related to Campbell Units 1, 2, and 3 and the ash disposal costs related to Campbell Units 1, 2, and 3 will be recorded, as spent, to a regulatory asset; and
- b. The Company may request recovery in future base rate proceedings, and upon Commission determination that the Company has incurred those costs as the result of reasonable and prudent actions, they shall be included in rates. The Company will ensure that the amounts recovered through a regulatory asset account are net of any accumulated depreciation amounts.

6. The parties agree that subsequent to the Commission's order approving this Settlement Agreement, the Company shall issue a competitive solicitation ("the One-Time Solicitation") which will include the following parameters:

- a. The One-Time Solicitation will seek projects which will provide the Company with capacity credit in the MISO Zone 7 starting in the 2025 Planning Year;
- b. The One-Time Solicitation will include two all source tranches:
 - i. The first tranche will seek up to 500 ZRCs of capacity and associated energy and renewable energy credits ("RECs"), if applicable, from PPAs with terms up to 10 years. This tranche will seek dispatchable, non-intermittent generation capable of dispatching up or down in every hour of the year in response to wholesale energy market signals, providing capacity which meets the Local Clearing Requirement of MISO Zone 7; and
 - ii. The second tranche will seek up to 200 ZRCs of capacity and associated energy and RECs, if applicable, secured from unaffiliated third parties via PPAs or other third-party agreements that do not result in Company ownership with terms up to 25 years, at the discretion of the bidder. This tranche will seek intermittent resources and dispatchable, non-intermittent clean capacity resources (including battery storage resources), providing capacity which meets the Local Clearing Requirement of MISO Zone 7. This tranche will furthermore take into consideration the ability of the offered capacity to meet the Local Clearing Requirement of MISO Zone 7 for the duration of the contract length. Prior to the issuance of the second tranche portion of the One-Time Solicitation, the Company shall hold a stakeholder meeting including parties to this case and energy storage developers to discuss methods to improve RFPs and response to solicitations with respect to stand-alone storage projects and hybrid-storage projects.
- c. The Company's acquisition of the 700 ZRCs and associated energy and RECs, if applicable, sought in the One-Time Solicitation shall be considered incorporated into the PCA approved in Paragraph 1 of this Settlement Agreement. However, the actual selected bid(s) will be submitted in Case No. U-21090 for Commission approval subsequent to the completion of the One-Time Solicitation;
 - i. In that approval proceeding, the Commission shall: (i) confirm whether the solicitation process followed by the Company is consistent with the requirements of the Settlement Agreement; (ii) grant approval of the recovery of the costs associated with the selected project(s) pursuant to applicable law or make a preliminary finding that the costs associated

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

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

7. The parties agree to the approval of the Company's proposed accounting request to defer expense related to the Campbell site severance and retention agreement, utilizing a regulatory asset to record the deferred amounts. The deferred amounts for 2022 will be capped at \$26 million. All amounts deferred for 2022 and beyond will be reviewed in future rate cases. This Settlement Agreement does not permit the Company to defer amounts related to the Campbell site severance and retention agreement outside of 2022.

- a. Consumers Energy will publicly file in Case No. U-21090 its community transition plan for Karn Units 1 through 4 within 150 days of all four Karn Units ceasing operation; and
- b. Consumers Energy will develop a draft community transition plan for the Campbell site. During the development of this draft community transition plan for the Campbell site, Consumers Energy will consult with community-based organizations and community members living in the area surrounding the retired assets on the community transition plan before finalizing and filing it for informational purposes in Case No. U-21090.

8. The parties agree to the extension of the annual competitive bidding process used to acquire the supply-side resource technologies specified in the PCA, as approved in Case No. U-20165 (collectively the "Annual Solicitations" and individually an "Annual Solicitation"), with certain modifications included below:

- a. Qualifying Facilities ("QFs") that the Company has a legal obligation to purchase from under PURPA (such facilities are referred to as "QFs" in this Settlement Agreement), may bid any technology into the Annual Solicitation but will be required to submit an offer consistent with the PPA terms sought in the Annual Solicitation;
- b. The competitive bid process shall be administered by an independent third party. The evaluation criteria and process is to be made available to all bidders submitting responses for the specific technology requested by the

Company, as part of the RFP, to ensure transparency. QFs may bid any technology that meets the requirements of PURPA. A ranking of proposals is to be used by the independent third party and provided to the Company for selection;

- c. In its September 9, 2021 Order in Case No. U-20852 the Commission adopted competitive bidding guidelines titled “Competitive Procurement Guidelines for Rate-Regulated Electric Utilities (Not for PUPRA Compliance) and “Competitive Procurement Guidelines For Rate-Regulated Electric Utilities for PURPA Avoided Cost and Capacity Determination.” The “Objective” of the adopted guidelines provides that when the guidelines are utilized by utilities, it is presumed that resulting projects and contracts are reasonable and prudent and in the event utilities diverge from the guidance provided in the guidelines, it is expected that the utility will provide sufficient justification in order to receive Commission approval and recovery. In the Annual Solicitation process, the Company will follow the Commission’s adopted guidelines, including the ability to diverge from the guidance as provided in the guidelines;
- d. The first competitive solicitation for the Company pursuant to this Settlement Agreement will be conducted no later than December 31, 2022. New full avoided cost rates stemming from each competitive solicitation will be filed with the Commission for review and approval within 30 days of the conclusion of each competitive solicitation;
- e. The Company will seek term lengths for competitively bid projects up to 25 years, at the discretion of the bidder;
- f. The Company will seek to acquire the target amount of capacity identified in the PCA for each Annual Solicitation period and may exceed that target amount depending on the amount of bids, the size of projects bid, cost and value, and variations in project commercial operation dates. Total newly acquired capacity will be reconciled against the amount of capacity projected in the PCA in the Company’s next IRP. (For example, if the Company acquired more capacity than planned, the proposed resource plan in the next IRP would incorporate that additional capacity with a potential reduction in the capacity needed going forward.);
- g. If the Company is unable to meet the target capacity amount identified in the PCA in any given Annual Solicitation, the remaining "open" capacity will not be offered to QFs. The remaining capacity would instead be addressed through the process described in Paragraph 8.f.;
- h. The parties agree and acknowledge that there are supply chain, energy security, labor, and environmental benefits associated with robust, local clean energy manufacturing capabilities. As part of the Company’s competitive bidding process, the parties agree that the Company will, to the extent

reasonably possible, incorporate clear, fair, and transparent criteria in the bid evaluation process to recognize value associated with clean energy supply chain diversification and sustainability, including intended use of Michigan manufactured components and low-carbon manufacturing as verifiable by life cycle assessment and/or disclosure using public, third-party verified environmental product declarations. The Company agrees to consult with parties to the settlement on the details of such bid evaluation criteria. Nothing in this settlement alters the opportunity for stakeholders and potential bidders to review and comment on any new proposed bidding criteria through the process as set forth in the MPSC's competitive bidding guidelines approved in MPSC Case No. U-20852 on September 9, 2021;

- i. The parties agree that the Annual Solicitation process does not restrict the Company's ability to make short-term capacity additions to address capacity shortfalls which cannot reasonably be addressed through the Annual Solicitation process; and
- j. The Company may pursue supply-side resource pilots for new and emerging technologies outside of an Annual Solicitation subject to cost and project approval in its future rate cases.

9. The parties agree that the new capacity that the Company intends to procure through the PCA, in each Annual Solicitation, shall be: (i) acquired through a competitive bidding process; and (ii) approximately 50% will be from PPAs and other third-party agreements that do not result in Company ownership and approximately 50% will be owned by the Company, as acquired through a competitive bidding process. The new capacity acquired from PPAs or other third-party agreements that do not result in Company ownership will not compete against the new capacity which will be owned by the Company. The Company will use commercially reasonable efforts to maintain the 50%/50% proportion for new IRP resources from 2022 through the Company's next IRP proceeding, and in no event shall any given annual solicitation result in the Company owning more than 60% of the new capacity acquired in such solicitation. The Company, in its sole discretion, may also choose to acquire more than 50% of its new capacity from third parties. The parties further agree that the Company's affiliates will

be prohibited from bidding on the portion of the Company's new capacity acquired from third parties.

10. The parties agree to the approval of the extension of the Company's FCM approved in Case No. U-20165 equal to the product of: (i) the annual PPA payment, and (ii) the Company's after-tax WACC based on its total capital structure, which is currently 5.62%, as updated from time to time by the MPSC in electric rate case final orders. The FCM will be applicable to all new PPAs, but will not apply to PPA amendments, PURPA PPAs, and Voluntary Green Pricing PPAs. The Company shall also not receive an FCM on any PPAs executed under the Company's Renewable Energy Plan. The FCM will be subject to the cap, as provided in Attachment A of the Settlement Agreement. The parties agree that nothing in this Settlement Agreement is intended to waive the requirements of MCL 460.6t(15).

11. The parties agree to the extension of the Company's PURPA avoided cost construct, as approved in Case No. U-20165 (based on the Company's Annual Solicitations), with certain modifications included below:

- a. The Company's PURPA avoided cost construct will be subject to review in the Company's future IRP filings, as opposed to separate biennial filings;
- b. QFs 150 kWac and below are eligible to receive full avoided cost rates regardless of the Company's capacity needs;
- c. Within 180 days subsequent to the Commission's approval of this Settlement Agreement, the Company shall initiate stakeholder outreach to develop a simplified agreement, tariff-based program, or other mechanism which will allow QFs 150 kWac and below to receive full avoided cost rates. Subsequent to the completion of the stakeholder outreach, at the earliest practicable date, the Company will file a proposal with the Commission for approval;
- d. When the Company does not have a PURPA capacity need, QFs above 150 kWac, that the Company has a legal obligation to purchase from under PURPA, are eligible to receive the Company's energy-only avoided cost rates. The Company's energy-only avoided cost rates shall be based on a forecast of LMPs for the first 5 years and actual LMPs for years 6 through 10. The

Company's energy-only avoided cost rates shall not include a payment for capacity;

- e. Current existing QFs, at or below the Company's PURPA must-purchase obligation MW threshold, with a PURPA-based PPA with the Company as of January 1, 2019 shall receive new PPAs, regardless of the Company's capacity need, upon the expiration of their current PPAs based on the Company's full avoided cost rates at the time of PPA expiration. QFs that entered a PPA with the Company prior to January 1, 2019 at an amount less than full avoided cost rates, such as reduced avoided cost rates based on the Planning Resource Auction ("PRA") rate and forecasted or actual LMPs and energy-only rates which only include an energy rate and do not provide a payment for capacity, shall not automatically receive a new PPA at the full avoided cost rate when their current PPA expires. QFs that have entered a PPA with the Company after January 1, 2019 are not eligible to receive a new full avoided cost rate PPA with the Company regardless of the Company's capacity need;
- f. QFs that the Company has a legal obligation to purchase from under PURPA, and which are eligible for full avoided cost rates, may select PPA terms up to 20 years; and
- g. QFs up to 5 MWac, that the Company has a legal obligation to purchase from under PURPA, are eligible for the Company's PURPA Standard Offer Tariff and Standard Offer Contract. The terms of the Standard Offer Contract will also be updated from using the MISO methodology for capacity accreditation at the time of PPA execution, to the average of the MISO methodologies at the time of PPA execution and delivery under the PPA. Within 30 days following the Commission's approval of this Settlement Agreement, the Company shall file revised Standard Offer tariff sheets and a revised Standard Offer contract, to reflect the Standard Offer construct and rates approved as part of this Settlement Agreement. Parties shall be given 14 calendar days subsequent to the Company's filing to provide comments to the Commission.

12. The Company has no PURPA capacity need so long as the Company is implementing the Commission-approved PCA, as provided in Paragraph 1, including the competitive Annual Solicitation process for future capacity needs.

13. The parties agree that the Company will donate \$5 million in 2022 to a low-income fund that provides bill assistance to Consumers Energy's electric customers. The Company will also donate \$2 million annually to the same low-income fund each year during the amortization period for the regulatory asset, provided in Paragraph 5 of this Settlement

Agreement, with each annual donation contingent on the Company filing and the Commission approving a Voluntary Revenue Refund (“VRR”). The donations described in this paragraph will not be recovered in rates and Consumers Energy will consult with the Attorney General and Staff on the low-income fund receiving the donations. The Company will provide an annual report to the Commission each year a donation is made. If known, the report will include the number of households served, the number of households over 150% of the federal poverty level (“FPL”), and number under 150% of the FPL. For those households 150% of FPL and under, the report will explain, if known, whether they are receiving the funds because they exhausted other benefits such as the Michigan Energy Assistance Program or State Emergency Relief.

14. In future IRPs, beginning with its next IRP, the Company will (i) collect the necessary data to compute marginal line losses and report these with average line losses and (ii) include marginal line losses and avoided transmission and distribution costs in its evaluation of all distributed resources, including residential DR potential.

15. Consumers Energy agrees to develop a distributed generation as a resource model approach that considers economic distribution connected solar to be modeled by bundling resources installed at the customer level to compare the total economic costs to the utility of distributed generation as a resource to other selectable supply-side resources, consistent with the methodology used for EWR. The Company will develop a model that accounts for all utility costs and/or incentives associated with participating and non-participating distributed generation customers. The Company agrees to present the model approach for stakeholder review and feedback prior to the next IRP. The model approach, including any incorporated stakeholder feedback, will be included into the Company’s next IRP.

16. The parties agree that Consumers Energy's IRP set forth a proposal to be Carbon Neutral by 2040 and retire all coal generation by 2025, 14 years ahead of the original timeline. These retirements include two substantial coal and gas units totaling approximately 2,000 MW. To replace the capacity, Consumers Energy has proposed adding existing natural gas-fired generation and plans to add about 8,000 MW of solar generation by 2040, to dramatically reduce the use of fossil fuel resources. The next IRP should consider transmission and how it can facilitate the mitigation of reliability and economic impacts to the electric system. The parties also agree that strategic investment in electric transmission needs continual assessment to understand the role of transmission in allowing for the most economic path to meeting the state's energy goals while complementing Michigan's Load Serving Entities' ("LSE") objectives. Michigan is transitioning its generation portfolio and must take the appropriate steps to increase system reliability, resiliency, flexibility, and affordability. Michigan will be better positioned by taking a forward-looking approach regarding resource adequacy. The state should continue to recognize and support the value of a multitude of resources such as Solar, Wind, DR, and Distributed Energy Resources which assist in an "all of the above" approach. Transmission is essential in delivering the reliability of these resources. The value of transmission can be even further realized by leveraging those transmission resources to better assist the Consumers Energy IRP. This will allow MISO LRZ 7 to access broader pools of generation resources, be better situated for future demands placed on the system, mitigate unnecessary risks, and increase performance of those "all of the above" resources to serve the demands of Michigan's customers reliably and economically.

17. The parties agree that the Company will include the following analysis in its next IRP:

- a. The Company will provide total emissions, in lbs or tons, and rate of emissions, in lbs or tons per MWh and per MMBtu, for each owned power plant unit, or units that the Company has a power purchase agreement with, for the last 5 years of operation (for existing units) and projected for the next 5 years (for all units) for the following pollutants: carbon dioxide, nitrogen oxides, sulfur dioxide, volatile organic compounds (“VOCs”), and primary particulate matter (“PM2.5”);
- b. The Company will calculate the annual PM2.5-related health impacts associated with each power plant’s emissions. The modeling will include the impacts from primary PM2.5 emissions and PM2.5 precursors emissions (nitrogen oxides, sulfur dioxide, VOCs). The Company will use one model to evaluate the number and economic value of PM2.5-related health impacts of these emissions. The Company may use COBRA or BenMAP (which will require pollutant change inputs from another model such as InMAP) for these calculations, or models that are of equal or greater complexity and accuracy. The Company will report the total number and economic value of PM2.5-related health impacts across the US for the chosen model and spatially by Michigan county or at a higher resolution;
- c. The Company will use the MiEJScreen mapping and screening tool, or, if the MiEJScreen tool is not yet finalized, the EPA Environmental Justice Screening and Mapping Tool (“EJSCREEN”), to assess populations in a 1-mile and 3-mile buffer around each power plant location, including reporting total populations and any indicators and total index results above the 75th percentile;
- d. The Company will report projected low-income energy efficiency participation levels, low-income load-reduction data, and publicly available rooftop solar adoption rates. If available, information on rooftop solar adoption by low-income customers will be provided;
- e. The Company will include a narrative discussion of how the data obtained in a-d were considered by the utility; and
- f. To the extent that the Commission formally adopts revised Integrated Resource Plan Filing Requirements and/or revised Michigan Integrated Resource Planning Parameters that address environmental emissions, health impacts from emissions, or environmental justice, such filing requirements will supersede the terms of this Paragraph 17.

18. The parties agree that the Company will take the following steps to engage and gather input from the public prior to the filing of its next IRP with the Commission:

- a. Host meetings about the topic of the filing at a variety of times, during the daytime and the evening, with the Company providing equivalent content and equivalent and sufficient time for robust public response at each session;
- b. Host meetings about the topics in the filing with a roughly equal mix between (i) in-person meetings and (ii) virtual or hybrid meetings;
- c. For the duration of the proceedings before the MPSC, make available on its website recordings of (i) all virtual or hybrid meetings and (ii) to the extent feasible, any portion of an in-person meeting in which the Company is (a) addressing all participants in the meeting and/or (b) receiving public feedback and/or questions in a format intended to be heard by all participants in the meeting at the same time;
- d. When requested 10 business days prior to a meeting, provide translations of materials for the benefit of those communities whose first language is not English, based on the demographics of the community;
- e. When requested within 30 days subsequent to a meeting, the Company will use best efforts to provide a translation of recordings of the community meeting in a language specified by the person requesting the translation. Such translation recordings will be provided within 15 business days, subject to the Company's best efforts, after the request is received. If the Company is unable, after a good faith effort, to find or reasonably engage the services of a translator capable of translating the recording into the language requested, the Company will not be obligated to provide the translation;
- f. When requested at least 10 business days prior to an in-person meeting, the Company will use best efforts to include at least one live interpreter who can translate in the requested language. If the Company is unable, after a good faith effort, to find or reasonably engage the services of a translator capable of translating the meeting into the language requested, the Company will not be obligated to provide the translation;
- g. Coordinate with community-based organizations when organizing and promoting meetings about the filing. The Company will solicit input regarding the time, place, and manner of the meetings from the community organizations, in addition to any other meetings the Company wishes to hold of its own accord;
- h. Use best efforts to present the details of the integrated resource planning process in accessible, non-technical language that includes, but is not limited to, descriptions of the impacts of the Company's plans on communities, the environment, and public health;
- i. Include in its filings a concise general statement of the basis and purpose of the comments received by the Company and how the Company considered,

addressed, or rejected the issues raised in those comments in the IRP (as practicable); and

- j. Subsequent to the issuance of the Commission's order approving this Settlement Agreement, the Company agrees to meet with UCC to discuss potential stakeholder outreach prior to or subsequent to future electric rate case filings.

19. The parties agree that the Company will do the following with respect to combined heat and power ("CHP") resources:

- a. Within 180 days of the effective date of the Commission's order approving the settlement, the Company will initiate a voluntary survey among its commercial and industrial customers to gauge interest in CHP (the "CHP survey"), with survey responses intended to be used by the Company to support the evaluation of: (1) the types of CHP that customers prefer, with regard to size, technology and overall configuration, on both the demand side and supply side, including co-ownership arrangements and other potential partnerships with the Company, and: (2) non-confidential information regarding locations within the Consumers Energy territory that may be most appropriate for deployment of CHP. The CHP survey will be conditioned on respondent approval of the public release of all information provided by the respondent in response to the survey. Nothing in this section is intended to require the public release of any confidential and/or commercially sensitive customer or Company information;
- b. Within 360 days of the effective date of the Commission's order approving the settlement, the Company will share the results of the CHP survey in the Case No. U-21090 e-docket, including a summary of the types of CHP that customers prefer, with regard to size, technology, and overall configuration, on both the demand side and supply side, including co-ownership arrangements and other potential partnerships with the Company; and a summary of non-confidential information regarding locations within the Company's territory that may be most appropriate for deployment of CHP, according to the CHP survey results;
- c. In its next IRP proceeding, the Company will model behind-the-meter CHP representative of a demand-side resource based upon the results from the CHP survey as appropriate; and
- d. In its next IRP proceeding, the Company will model front-of-the-meter CHP configurations based upon the results from the CHP survey as appropriate.

20. This settlement is entered into for the sole and express purpose of reaching a compromise among the parties. All offers of settlement and discussions relating to this settlement are, and shall be considered, privileged under MRE 408. If the Commission approves this Settlement Agreement without modification, neither the parties to this Settlement Agreement nor the Commission shall make any reference to, or use, this Settlement Agreement or the order approving it, as a reason, authority, rationale, or example for taking any action or position or making any subsequent decision in any other case or proceeding; provided, however, such references may be made to enforce or implement the provisions of this Settlement Agreement and the order approving it.

21. This Settlement Agreement is based on the facts and circumstances of this case and is intended for the final disposition of Case No. U-21090. So long as the Commission approves this Settlement Agreement without any modification, the parties agree not to appeal, challenge, or otherwise contest the Commission order approving this Settlement Agreement. Except as otherwise set forth herein, the parties agree and understand that this Settlement Agreement does not limit any party's right to take new and/or different positions on similar issues in other administrative proceedings, or appeals related thereto.

22. This Settlement Agreement is not severable. Each provision of the Settlement Agreement is dependent upon all other provisions of this Settlement Agreement. Failure to comply with any provision of this Settlement Agreement constitutes failure to comply with the entire Settlement Agreement. If the Commission rejects or modifies this Settlement Agreement or any provision of the Settlement Agreement, this Settlement Agreement shall be deemed to be withdrawn, shall not constitute any part of the record in this proceeding or be used for any other purpose, and shall be without prejudice to the pre-negotiation positions of the parties.

23. The parties agree that approval of this Settlement Agreement by the Commission would be reasonable and in the public interest.

24. The parties agree to waive Section 81 of the Administrative Procedures Act of 1969 (MCL 24.281), as it applies to the issues resolved in this Settlement Agreement, if the Commission approves this Settlement Agreement without modification.

WHEREFORE, the undersigned parties respectfully request the Commission to approve this Settlement Agreement on an expeditious basis and to make it effective in accordance with its terms by final order.

MICHIGAN PUBLIC SERVICE COMMISSION STAFF

By: **Spencer Sattler**
Digitally signed by Spencer Sattler
Date: 2022.04.19 14:00:30 -04'00'

Date: April 19, 2022

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CONSUMERS ENERGY COMPANY

By:  Digitally signed by
Robert W. Beach
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Date: April 19, 2022

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Bret A. Totoraitis (P72654)
Robert W. Beach (P73112)
Anne M. Uitvlugt (P71641)
Gary A. Gensch (P66912)
Theresa A. G. Staley (P56998)
Michael C. Rampe (P58189)
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Attorneys for Consumers Energy Company

ATTORNEY GENERAL, DANA NESSEL

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Date: _____

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Date: April 19, 2022

MICHIGAN ENVIRONMENTAL COUNCIL

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Date: April 19, 2022

NATURAL RESOURCES DEFENSE COUNCIL

By:  Digitally signed by
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Date: April 19, 2022

SIERRA CLUB

Michael C. Soules
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CITIZENS UTILITY BOARD OF MICHIGAN



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

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Date: April 19, 2022

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

By: **Laura A. Chappelle**
Laura A. Chappelle, Esq.
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Digitally signed by
Laura A. Chappelle
Date: 2022.04.19
12:42:00 -04'00'

Date: April 19, 2022

MICHIGAN ELECTRIC TRANSMISSION COMPANY, LLC

By: **Richard**
Aaron
Richard J. Aaron, Esq.
Dykema Gossett PLLC
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Digitally signed by: Richard Aaron
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Dykema
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ENVIRONMENTAL LAW & POLICY CENTER, VOTE SOLAR, ECOLOGY CENTER, AND
UNION OF CONCERNED SCIENTISTS

By: 
Margrethe Kearney, Esq.
Environmental Law & Policy Center
146 Monroe Ctr St. NW, Ste 422
Grand Rapids, Michigan 49503

Date: April 19, 2022

HEMLOCK SEMICONDUCTOR OPERATIONS LLC

By: **Jennifer
Utter
Heston**  Digitally signed by
Jennifer Utter
Heston
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13:15:32 -04'00'

Jennifer Utter Heston, Esq.
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124 West Allegan, Suite 1000
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Date: April 19, 2022

URBAN CORE COLLECTIVE



By:

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Andrew Bashi, Esq.
Great Lakes Environmental Law Center
Local Counsel for Urban Core Collective
4444 2nd Avenue
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19-April-2022

Date:

Mark N. Templeton, Esq.
Robert A. Weinstock, Esq.
University of Chicago Law School –
Abrams Environmental Law Clinic
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Chicago, IL 60637

The following parties do not wish to be signatories to this Settlement Agreement; however they have agreed to sign below to indicate non-objection to the Settlement Agreement.

MICHIGAN PUBLIC POWER AGENCY

By: Nolan J. Moody Digitally signed by Nolan J. Moody
Date: 2022.04.19 12:19:10 -04'00'

Date: April 19, 2022

Nolan J. Moody, Esq.
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MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP

By: **John Janiszewski**
Digitally signed by: John Janiszewski
DN: CN = John Janiszewski email
= jjaniszewski@dykema.com C =
US O = Dykema Gossett, PLLC
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John A. Janiszewski, Esq.
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201 Townsend Street, Suite 900
Lansing, MI 48933

Date: April 20, 2022

ATTACHMENT A

ATTACHMENT A

Contract Year	Total Rate (\$/MWh)
2019	\$ 55.54
2020	\$ 57.49
2021	\$ 59.38
2022	\$ 61.28
2023	\$ 63.25
2024	\$ 65.24
2025	\$ 67.24
2026	\$ 69.24
2027	\$ 71.23
2028	\$ 73.18
2029	\$ 75.08
2030	\$ 76.95

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

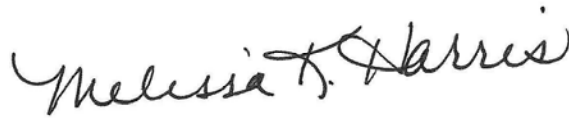
In the matter of the application of)
CONSUMERS ENERGY COMPANY)
for Approval of an Integrated Resource Plan)
under MCL 460.6t, certain accounting)
approvals, and for other relief.)
_____)

Case No. U-21090

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 April 20, 2022, she served an electronic copy of the **Settlement Agreement**, upon the persons listed in Attachment 1 hereto, at the e-mail addresses listed therein.



Melissa K. Harris

Subscribed and sworn to before me this 20th day of April 2022.



Crystal L. Chacon, Notary Public
State of Michigan, County of Ingham
My Commission Expires: 05/25/24
Acting in the County of Jackson

ATTACHMENT 1 TO CASE NO. U-21090

**Administrative Law Judge
(Electronic Copy of Public Materials)**

Hon. Sally L. Wallace
Administrative Law Judge
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Energy, LLC, Genesee Power Station
Limited Partnership, Decker Energy-
Grayling, LLC, Hillman Power
Company, LLC, Tondue Corporation,
Viking Energy of Lincoln, LLC., and
Viking Energy of McBain, LLC
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ATTACHMENT 1 TO CASE NO. U-21090

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ATTACHMENT 1 TO CASE NO. U-21090

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ATTACHMENT 1 TO CASE NO. U-21090

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Attachment II

Campbell Clean Air Markets Permit Data
April through June 2025

Campbell Clean Air Markets Permit Data_April through June 2025

State	Facility Name	Facility ID	Date	Gross Load (MWh)	Steam Load (1000 lb)	SO2 Mass (short tons)	CO2 Mass (short tons)	NOx Mass (short tons)	Heat Input (mmBtu)
MI	J H Campbell	1710	4/1/2025	32089		26.073	34432.5	11.808	328302.7
MI	J H Campbell	1710	4/2/2025	32172		26.708	33475.6	12.115	319178.4
MI	J H Campbell	1710	4/3/2025	32151		26.75	34020	11.657	324369.8
MI	J H Campbell	1710	4/4/2025	32355		26.805	34989.3	13.344	333611.8
MI	J H Campbell	1710	4/5/2025	32139		26.271	34246.3	11.888	326528.9
MI	J H Campbell	1710	4/6/2025	31057		26.898	33385.1	12.257	318317
MI	J H Campbell	1710	4/7/2025	32303		25.336	34027.9	11.128	324446.2
MI	J H Campbell	1710	4/8/2025	31873		24.933	34003.7	10.998	324215.6
MI	J H Campbell	1710	4/9/2025	32176		27.797	34070.5	11.174	324853.1
MI	J H Campbell	1710	4/10/2025	31764		25.402	33952.3	12.089	323724.9
MI	J H Campbell	1710	4/11/2025	31496		26.446	33966.7	11.057	323860.3
MI	J H Campbell	1710	4/12/2025	31303		25.894	33729	11.192	321600.7
MI	J H Campbell	1710	4/13/2025	31226		24.015	33475.1	13.026	319173.1
MI	J H Campbell	1710	4/14/2025	31234		24.5	32939.5	11.254	314068.6
MI	J H Campbell	1710	4/15/2025	31080		25.949	32714.6	10.89	311923.8
MI	J H Campbell	1710	4/16/2025	31237		28.469	33287.8	10.532	317387.7
MI	J H Campbell	1710	4/17/2025	29930		21.47	32216	10.808	307168.1
MI	J H Campbell	1710	4/18/2025	28316		19	30354.4	9.414	289421.6
MI	J H Campbell	1710	4/19/2025	25958		18.637	28635.8	8.053	273034.7
MI	J H Campbell	1710	4/20/2025	29482		20.061	32391.4	11.031	308840.6
MI	J H Campbell	1710	4/21/2025	30425		21.088	32404.1	11.24	308962.7
MI	J H Campbell	1710	4/22/2025	25512		21.484	28261.1	8.827	269457.3
MI	J H Campbell	1710	4/23/2025	28850		24.864	31580.4	10.731	301106.5
MI	J H Campbell	1710	4/24/2025	27740		22.961	30597.2	9.892	291741.5
MI	J H Campbell	1710	4/25/2025	29740		22.45	32159.3	10.749	306627
MI	J H Campbell	1710	4/26/2025	31485		22.98	34008.4	10.551	324257.5
MI	J H Campbell	1710	4/27/2025	31466		23.072	34242.8	10.109	326495.2
MI	J H Campbell	1710	4/28/2025	30316		20.833	32845.4	10.909	313170.6
MI	J H Campbell	1710	4/29/2025	30839		22.913	32788.7	10.647	312629
MI	J H Campbell	1710	4/30/2025	31662		24.814	34494.8	10.864	328897.7
MI	J H Campbell	1710	5/1/2025	30322		22.873	32375.1	9.675	308680.3
MI	J H Campbell	1710	5/2/2025	28216		22.048	30575.2	9.443	291522.2
MI	J H Campbell	1710	5/3/2025	22074		16.599	25294.4	6.504	241172.5
MI	J H Campbell	1710	5/4/2025	22073		16.49	25425.5	6.467	242426.9
MI	J H Campbell	1710	5/5/2025	22091		16.615	25436.4	6.548	242529.7
MI	J H Campbell	1710	5/6/2025	26267		19.672	29130.8	9.17	277759.2
MI	J H Campbell	1710	5/7/2025	22090		16.439	25000.1	6.817	238367.6
MI	J H Campbell	1710	5/8/2025	22282		16.695	25383.4	6.809	242021
MI	J H Campbell	1710	5/9/2025	23955		16.419	27064.6	19.309	258050.3
MI	J H Campbell	1710	5/10/2025	24404		16.383	27386.3	7.417	261119.7
MI	J H Campbell	1710	5/11/2025	25767		16.054	29057.5	9.509	277055.4
MI	J H Campbell	1710	5/12/2025	24808		16.787	27681.5	7.82	263933.1
MI	J H Campbell	1710	5/13/2025	24145		16.824	26722.3	8.264	254793.7
MI	J H Campbell	1710	5/14/2025	25800		17.161	27964.9	9.194	266640.6
MI	J H Campbell	1710	5/15/2025	25534		18.358	27393.2	8.68	261184.7
MI	J H Campbell	1710	5/16/2025	25884		21.226	27229.3	8.345	259617.5
MI	J H Campbell	1710	5/17/2025	25873		21.016	27440.9	8.345	261642.6
MI	J H Campbell	1710	5/18/2025	25855		18.826	28098.1	8.359	267907.4
MI	J H Campbell	1710	5/19/2025	22723.05		13.002	24874.5	8.244	237170.66
MI	J H Campbell	1710	5/20/2025	22034		12.248	23798.5	7.7	226912.5
MI	J H Campbell	1710	5/21/2025	22038		13.097	23737.6	8.281	226333.3
MI	J H Campbell	1710	5/22/2025	22045		13.173	23707.6	8.013	226045.4
MI	J H Campbell	1710	5/23/2025	21337		11.495	23456.9	7.645	223656.3
MI	J H Campbell	1710	5/24/2025	17095		11.624	19596.7	5.613	186850.3
MI	J H Campbell	1710	5/25/2025	18308		11.782	20809.7	6.815	198414.4
MI	J H Campbell	1710	5/26/2025	22065		10.3	24626.6	7.598	234809.7
MI	J H Campbell	1710	5/27/2025	19709		12.083	22452	7.241	214074.5
MI	J H Campbell	1710	5/28/2025	18494		9.219	21428.1	6.569	204309.6

MI	J H Campbell	1710	5/29/2025	19371		12.182	22131.8	7.141	211024.6
MI	J H Campbell	1710	5/30/2025	18420		9.888	20933.6	6.03	199597.3
MI	J H Campbell	1710	5/31/2025	18404		10.317	20732	5.945	197672.4
MI	J H Campbell	1710	6/1/2025	18402		11.914	20959.9	5.778	199845.9
MI	J H Campbell	1710	6/2/2025	18407		9.438	21310.7	5.861	203189.3
MI	J H Campbell	1710	6/3/2025	21789		11.032	24122.7	8.487	230003.8
MI	J H Campbell	1710	6/4/2025	23066		11.679	25206.1	9.319	240330.8
MI	J H Campbell	1710	6/5/2025	23020		11.924	25439.3	9.945	242555.2
MI	J H Campbell	1710	6/6/2025	22673		10.928	24945.9	8.261	237852.4
MI	J H Campbell	1710	6/7/2025	22113		10.139	24192.3	7.608	230665.8
MI	J H Campbell	1710	6/8/2025	22118		9.406	23942.1	7.33	228282
MI	J H Campbell	1710	6/9/2025	22424		12.085	24294.9	7.807	231643.1
MI	J H Campbell	1710	6/10/2025	23758		13.433	25759.3	9.594	245607.1
MI	J H Campbell	1710	6/11/2025	23792		12.41	26072.6	9.105	248594.7
MI	J H Campbell	1710	6/12/2025	22556		11.473	25086.9	8.296	239194.8
MI	J H Campbell	1710	6/13/2025	23446		11.804	25661.2	8.688	244672.2
MI	J H Campbell	1710	6/14/2025	23736		12.018	25815.8	8.622	246144.6
MI	J H Campbell	1710	6/15/2025	23745		11.657	25918.3	8.639	247124.3
MI	J H Campbell	1710	6/16/2025	23718		12.609	26091.8	8.733	248775.4
MI	J H Campbell	1710	6/17/2025	23455		11.961	25588.6	8.596	243982
MI	J H Campbell	1710	6/18/2025	22919		12.091	25266	8.742	240905.7
MI	J H Campbell	1710	6/19/2025	24103		13.074	26558.1	9.321	253222.6
MI	J H Campbell	1710	6/20/2025	24333		14.197	26927	9.382	256742.7
MI	J H Campbell	1710	6/21/2025	24347		18.749	26747	9.535	255024.7
MI	J H Campbell	1710	6/22/2025	24318		15.558	26949.7	9.326	256960.4
MI	J H Campbell	1710	6/23/2025	21733.2		9.815	23765.765	7.674	226604.025
MI	J H Campbell	1710	6/24/2025	18225		4.594	19308.1	6.307	184096.5
MI	J H Campbell	1710	6/25/2025	18227		4.722	19374.518	5.734	184729.064
MI	J H Campbell	1710	6/26/2025	18195		6.064	19897.107	7.519	189713.68
MI	J H Campbell	1710	6/27/2025	18362		4.885	20055.01	5.87	191220.855
MI	J H Campbell	1710	6/28/2025	22283		15.205	23612.2	8.273	225135.1
MI	J H Campbell	1710	6/29/2025	22857		19.207	23882.5	7.001	227712.2
MI	J H Campbell	1710	6/30/2025	22247		13.277	23872.2	6.581	227617.2